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TORQUE AND DRAG ANALYSIS

A Thesis
By

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ABSTRACT

Drilling through the subsurface is a complex operation and problems are almost guaranteed to occur. Therefore, understanding and anticipating drilling problems, understanding their causes and planning solutions are necessary for successfully reaching the target. The most prevalent drilling problems include pipe sticking, lost circulation, hole deviation, pipe failures, borehole instability, mud contamination, formation damage, hole cleaning.

Torque and drag modeling is very important to analyze the mechanical behavior of the drill string and the wellbore condition, hence, to predict and prevent downhole problems. There have been a number of different approaches to the way that torque and drag has been modeled in the well drilling industry. These include the soft string and stiff string approaches.

This thesis will study the torque and drag in the wellbore and will give a general overview of the sources, effects and challenges of torque, drag and buckling in the wellbore. Furthermore, it will study and simulate the soft string model to calculate torque and drag along a drill string in a 12 1/4" vertical section wellbore as well as provide calculations of hook-loads and frictional torque for specific bit depths. Additionally, it will provide a simulation of the section with the PayZone drilling simulator to calculate the torque on bit while drilling. Both the model and the PayZone values are summed up together to get the cumulative torque which is the torque observed at the surface while drilling.

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1 INTRODUCTION

1.1 Introduction to Drilling

When locating and extracting hydrocarbons from reservoirs, a hole must be drilled into the earth. This hole is known as an oil or gas well, depending on the type of hydrocarbons produced in the reservoir. Well drilling is achieved by complex processes and techniques; it is typically done by using special platforms known as Drilling Rigs. In drilling rigs, there is a rotating drilling string with a bit attached to it, and the bit is rotated and simultaneously forced against the rock formations in order to overcome the resistance of the rocks and break or crush the rocks into small particles. It is then brought back to the surface by a drilling fluid - usually by a liquid, a gas, or foam – that is pumped from the surface through the drill string, down to the bit and then back to the surface through the annulus between the hole and the drilling string. Besides removing cuttings particles from the hole, drilling mud is used to maintain the stability of the walls of the well and prevent formation fluid influx into the well while drilling and during suspensions. The drilling rigs are complexes of mobile equipment which can be relocated to different drilling sites.

Traditionally, the rotation of the drilling string is introduced at the surface by a rotary table. In modern rigs, the rotation is generated by a top drive motor and then transmitted to the bit by the drill string, which in this case are circular pipes connected to each other, as well as some special tools and pipes to add weight, allow for reaming and center the string in the hole. In addition, they orient the well into a specific direction, downhole measurements, and add rotation such as the mud motor located above the bit; all together these components are called Bottom Hole Assembly (BHA).

Drill bits are the most refined tools in the rotary system; bits are available for every condition of drilling, and certain types of bits are used for specific formation hardness. Two types of bits are widely used in the rotary system – the first type is Polycrystalline Diamond Compact (PDC) bits, which are made of heat-treated alloy

steel or a tungsten carbide matrix body with fixed cutters attached to the bit face, which would be in contact with formation rocks. These cutters are made by bonding a layer of synthetic polycrystalline diamond to a cemented tungsten carbide substrate in a high temperature and pressure process. The hard and wear-resistant diamond is produced at the end of this process, which penetrates rocks in a shearing mechanism. The other type is roller cone bit; it is made of a body with three rotating cones with casted or inserted teeth to break the rocks.

After the hole is drilled to a predetermined depth, sections of steel tubing slightly smaller than the borehole, known as casing strings, are set in the hole to provide an annulus for cementing. The casing provides structural integrity to the newly drilled wellbore and isolates any potentially dangerous high pressure zones from each other and from the surface.

With these zones safely isolated and the formation protected by the casing, the well can then be drilled deeper, often into potentially more unstable formations. Here, a smaller bit and smaller size casing is used. Modern wells often have two to five sets of subsequently smaller hole sizes drilled, each inside one another and each cemented with a differently sized casing.

During drilling operations, sub-surface pressures must be continuously controlled as the various layers of the downhole formation are pierced by the wellbore. "Downhole blowouts" can often occur when a zone of high pressure is penetrated and uncontrolled pressure starts flowing to another zone of lower pressure. To control this situation, mud pressure is increased above the pressure in the formation. This form of well control is called "primary well control", and pressure is maintained and closely monitored throughout the entire well drilling process. In the secondary well control approach, a blowout preventer is activated which seals off the well annulus to prevent the downhole pressure from reaching the surface.

1.2 Historical Perspective

During the 1860s, the oil industry started to develop and wells were drilled using cable tool rigs that originated in China. This was the best method available until 1900, as cable tool rigs were very slow and were operated by lifting and dropping a special string into the hole.

The rotary system was developed in 1901 to drill deeper and faster and eventually became the common method to drive the rigs until the present day. (Please, do not use a comma before the "and" word)

1.3 Deviation and Directional Wells

Most of the wells drilled today are directional wells to increase exposure to producing zones and intersect a larger number of fractures. Directional wells deviate from the vertical position of the wellbore path. Deviations can occur naturally from the result of inserting the drill string to the downhole structure, such as fractures and formation dipping. However, wells are often deliberately deviated by the use of a steering mechanism attached to the drill string.

Multiple directional wells can be drilled from the same pad, which is common in offshore drilling. The most common method is when a driller moves the rig a few yards and starts another vertical shaft. Multiple wells can also be drilled from the same vertical borehole to reach different zones.
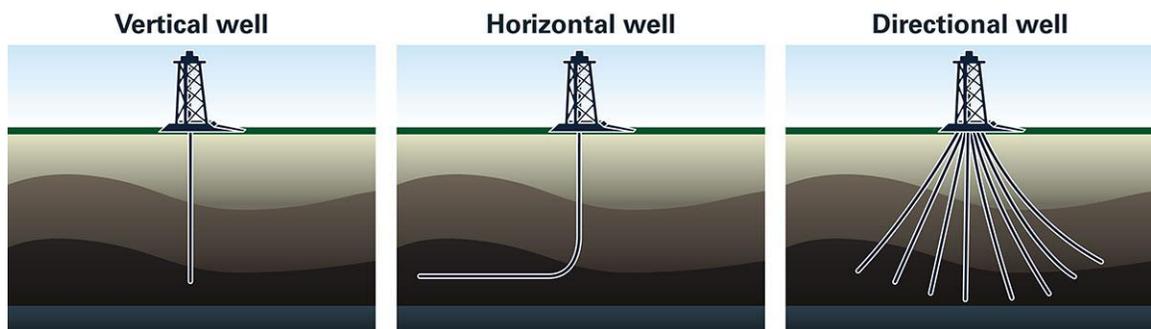
Figure 1.1 Different types of wells [1]

1.4 Drilling Problems

Drilling through the subsurface is a complex and risky operation and problems are almost guaranteed to occur. Therefore, it is always important to predict potential problems rather than caution and containment, which is a key issue while designing the well.

The most prevalent drilling problems include pipe sticking, lost circulation, hole deviation, pipe failures, borehole instability, mud contamination, formation damage, hole cleaning, H2S -bearing formation, shallow gas, and equipment and personnel-related problems [2].

This thesis will study the torque and drag in the wellbore. Torque and drag modeling is a very important tool used to avoid drilling problems and allows for further drilling, especially in complex and extended reach wells, where the loads are usually near the limits of the available tools and materials.

2 LITERATURE STUDIES

2.1 Torque and Drag Definition

2.1.1 Drag

Drag is defined as the increase in the drill string weight when pulling out of the hole, or the reduction of the weight while running in the hole. In other words, drag is the force difference between the static weight and the force required to move the string up or down in the hole. Thus, the observed weight of the drill string on the surface is either heavier or lighter than the actual weight, depending on the direction of the drill string motion. The observed weight of the string is lower than the actual weight while running in the hole and the direction of the drag force is upwards. While pulling the string out of the hole, the observed weight of the string is higher than the actual weight and the direction of the drag force is downwards.

Hence, drag on the drill string is the difference between the apparent weight and the actual weight. Drag is negative when the string moves downwards; therefore, there will be reduction in the string weight. Drag is positive when the string moves upwards, which means the apparent weight is higher than the actual weight.

$$\text{Drag force} = \text{Apparent weight} - \text{Actual weight}$$
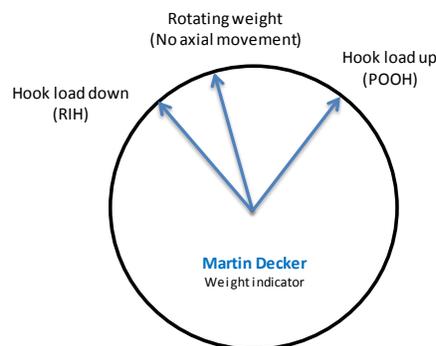
Figure 2.1 Hook load as observed on the surface

2.1.2 Torque

Torque, also called moment of a force in physics, is the tendency of a force to rotate the body to which it is applied. The torque, specified with regards to the axis of rotation, is equal to the magnitude of the component of the force vector lying in the plane perpendicular to the axis, multiplied by the shortest distance between the axis and the direction of the force component. Regardless of its orientation in space, the force vector can always be located in a plane parallel to the axis [3].

When it comes to torque in a drilling context, it is the moment required to rotate the drill string that will overcome the rotational friction between the drill string and the well bore, as well as the torque on the bit. The torque observed on the surface is usually higher than the torque caused by the drill bit; this is mainly because of the rotational friction torque in the well. The torque loss is greater in deviated wells, especially in complex or extended reach and horizontal wells, where torque is a major problem due to the rig and drill string torque limitation. However, the torque loss would be zero in a perfectly vertical well, except for the small viscous torque generated by the mud.
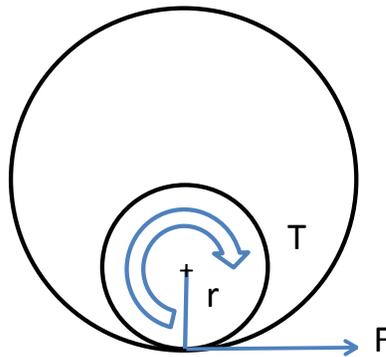
Figure 2.2 Torque to rotate the pipe

2.2 Sources

There are many parameters that cause torque and drag along the drill string. The main parameters are calculated, whereas some of the parameters cannot be calculated.

They are summed together and included in the friction factor. The main causes for excessive torque and drag are hole instability, key seating, differential sticking, poor hole cleaning, and wellbore friction [4].

Hole Instability: Hole instability such as swelling shale, tight hole, and sloughing shale increases the torque and drag because they change the original shape and size of the hole which increases friction between the wellbore and the drill string. Interaction between the drilling mud and the formation affects the friction and results in erosion in the well. Loss of circulation has an impact on the friction as it gives rise to friction in the wellbore due to lack of lubrication.

Key Seating: Key seating is the condition where a tube of small diameter is worn into the side of a borehole with a larger diameter (Figure 2.3). It is generally a result of severe hole direction changes, such as a high dogleg or a hard formation ledge left in soft formations which erode and enlarge with time. In both cases, the diameter of the drilled hole is expected to be close to the diameter of the drill pipe. The larger diameter tools such as stabilizers, drill collars, and tool joints are not able to pass through the key seat and become stuck, which will result in problems associated with high torque and drag. The preventive method is to enlarge the point of the key seat so that the tools with larger diameters can pass through it [5].
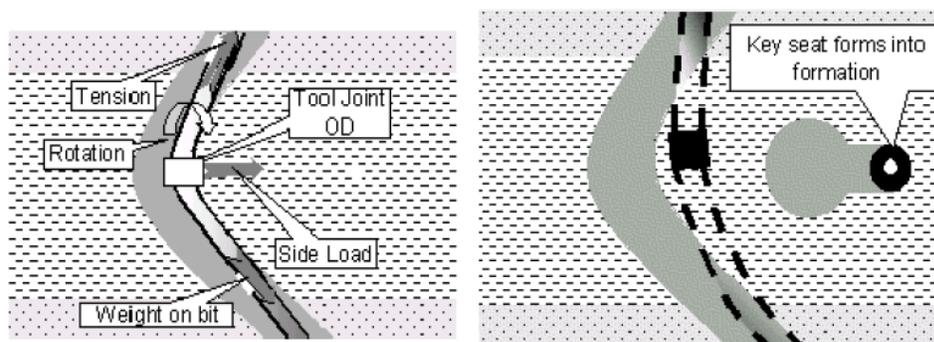
Figure 2.3 Key seating

Differential Sticking: Differential sticking occurs when high wellbore pressure causes a high contact force of the drill string against the wall of low formation pressure in typically high permeable zones. Differential pressure appears when the hydrostatic pressure of a drilling fluid acting on the outside wall of the drill pipe is greater than the formation fluid pressure and results in a sticking force. The drill string will be difficult to rotate or move axially, which increases torque and drag.
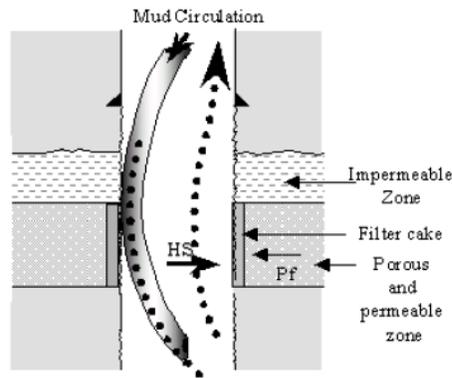
Figure 2.4 Differential sticking mechanism

Poor Hole Cleaning: Hole cleaning is one of the main issues while drilling. Improper cleaning can cause improper cuttings transport; there is subsequently an accumulation of cuttings in the wellbore and high angle section of cutting beds are formed. These conditions increase the friction inside the wellbore and cause high torque and drag. An increase in Equivalent Circulating Density (ECD) can indicate improper hole cleaning.
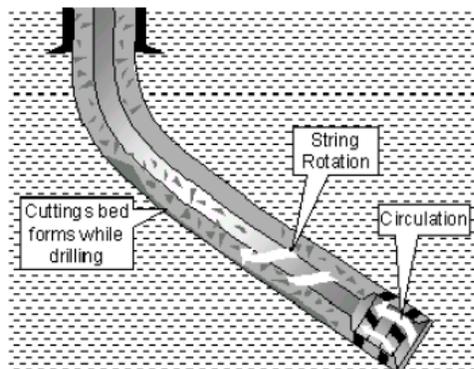
Figure 2.5 Settled cuttings due to poor cleaning

Wellbore Friction: Friction occurs because of the interaction between the drill string and the wellbore as frictional forces are generated against the direction of motion. The friction factor is defined as the measure of the degree of resistance to motion of two adjacent elements sliding against each other. It is the ratio of the frictional force to the normal contact force and is affected by the drilling fluid and formation type. Friction factors can be estimated for open hole and cased hole settings according to previous drilling experiences in corresponding formations and mud types for modeling. Minimizing the normal force will be effective on proper weight transfer to the bit. Methods for reducing normal force carefully design a well path and use string components of lower weight [6].

2.3   Types of Torque

There are three types of torque observed downhole: frictional torque, mechanical torque, and bit torque [7].

2.3.1   Frictional Torque

Contact loads between the drill string and casing or open hole section of a well generate frictional torque. It is the only torque type generated while rotating off-bottom in a perfectly cleaned wellbore. The following parameters determine the magnitude of frictional torque:

Tension/Compression in the Drill String: Increasing tension in the drill string increases contact forces; hence, it increases frictional torque. Both tension and frictional torque are affected by the weight on bit.

String Weight: As the string weight is increased, more weight is pushed at the side of the hole, resulting in higher contact forces that yield more frictional torque.

Dogleg Severity: A dogleg is the dramatic change of wellbore direction in three-dimensional space, which increases the contact forces. This is generally a concern at shallower depths where the tension in the string is high. As the tension in the drill string gets lower as depth in the hole increases, the effects of dogleg severity become negligible.

Inclination: Higher inclination values yield larger components of drill string weight perpendicular to the borehole, increasing thus normal forces. Conversely, torque can decrease at very high inclinations, as more of the string weight is taken by the borehole wall; hence, decreasing the contact forces.

Hole and Pipe Size: The space between the drill string and hole is called the annulus. A smaller annulus increases the effective stiffness of the pipe and increases contact forces.

Lubricity & Friction Factor: Lubricity is controlled by the drilling fluid and formation type, but it also controls friction. During drilling in abrasive formations, significant torque changes can be seen.

2.3.2 Mechanical Torque

Mechanical torque is caused by cutting accumulations in the wellbore due to poor cleaning because of poor hydraulics; therefore, there is an increase in friction inside the wellbore. In addition, unstable formations such as sloughing and swelling formations, which are affected by the drilling fluid, generates mechanical torque. Differential sticking of the drill pipe generates mechanical torque when it is difficult to rotate the pipe.

2.3.3 Bit Torque

Bit torque is generated from the interaction between the drill bit and the formation. The factors affecting bit torque are WOB, RPM, formation characteristics, PDC bit design variations, bit wear, and hydraulics [8].

2.4 Challenges

Weight Transfer to Bit: Weight transfer to the bit is achieved by slacking off at the surface or pushing down. Drag force is the difference between the actual weight available at the bit and the amount slacked off at the surface that is opposite to the pipe movement. Controlling the weight on the bit becomes difficult as depth or horizontal displacement increases because of the elasticity of the pipes. The elasticity will cause part of the pipes to move while other parts are stationary, or it will cause

movement at different velocities. Weight is occasionally suddenly released because of the difference between kinematic and static friction that occurs between the drill string and casing or open hole. Hang-ups such as key seats, ledges, and uneven cutting beds also contribute to the sudden release of the bit.

The bit rotation will suddenly stop if a weight transfer is released from the drill string that exceeds the maximum weight that the motor can withstand. Such a condition is called a motor stall and it is destructive for the rubber component of the motor.

The longitudinal drag of the drill string increases with increasing horizontal departure of a well. Hence, weight transfer to the bit without the stalling motor becomes more difficult, and drilling becomes more challenging.

2.5   Reduction of Torque and Drag

There is a variety of methods available to reduce torque and drag, if a well is drilled and the torque is much higher than predicted and exceeds the top-drive capacity of the rig. The application of such methods can be essential for ensuring that the TD can be reached before reaching the torque limit of the rig or drill string.

2.5.1   Wellpath

Tortuosity reduction significantly reduces the torque and drag while drilling. The use of RSS is recommended to make the smoothest wellbore. Finding compromises with geologists may be very beneficial, as even small adjustments to the target may reduce the torque. Reducing the DLS in build-up, drop off and bends can significantly reduce torque and drag, especially at the top of the well where tension forces are greatest.

2.5.2   Rotary Steerable Systems

A hole drilled using a mud motor with a bent sub generally has greater tortuosity than with a RSS, due to the steering principle of such tools. Directional drillers obtain the desired DLS by switching from rotary drilling to sliding drilling as many times as needed. Rotary drilling with a motor creates a smaller hole than with sliding drilling. Drilling with a motor creates a larger hole than a RSS would, whereas with sliding drilling, a high DLS is utilized to correct for the direction achieved by rotary drilling,

due to a combination of gravity and centralizer placement. This continued alteration is the reason why motors create much more tortuosity than a RSS. Adding a mud motor to an RSS will increase ROP, while RPM at the surface can be reduced to a minimum and thus reduce the torque. Using RSS with an integrated mud motor will reduce surface torque as compared to a conventional RSS.

2.5.3 Bit Selection

Bit selection is normally based on ROP, steer ability, and durability, but another factor is important as well. The gauge length can significantly affect the propagation of a cyclic hole. A short gauge bit is more aggressive and creates more caliper variations and what is called micro tortuosity, whereas a long gauge bit tends to create fewer caliper variations and a smoother hole. The micro tortuosity is not seen by MWD directional sensors, and will add extra torque and drag. This can be seen as measured torque and drag trends deviate from simulated trends.

2.5.4 Mechanical Friction Reduction Subs

Mechanical friction reducing subs have been tried and proven successful in reducing friction. Use of mechanical friction reduction tools and other techniques for reducing friction have shown to be effective. Various types exist, but either they consist of mechanical rollers, or a sleeve on bearings, which then becomes the effective contact surface. The low friction in a smooth bearing relative to rough steel against rough steel reduces the torque and drag significantly. The subs are typically placed one per stand in the sections of the well that sees the highest side force.

2.5.5 Mud System

The easiest way to reduce torque and drag is to use oil-based mud (OBM) or synthetic based mud (SBM) instead of water based mud (WBM). It is also possible to add lubricants, even to WBM.

3 TORQUE AND DRAG MODELING

3.1 Background

Software for torque and drag models has been developed and used in the industry and is crucial in avoiding drilling problems and allowing for further drilling, especially in complex and extended reach wells, where the loads are usually near the limits of the available tools and materials.

During the well planning, torque and drag models are used to validate the planned well path that can be drilled within the equipment's limits and rig capacity. These models are then used for load analysis to optimize the well path design, to minimize torque and drag and to ensure that the torque is within safe working limits for the drill string and rig equipment.

The planned well path is designed for ideal smooth curves to counter the real well path which has tortuosity, so that planned paths cause the model to predict torques and drags lower than the actual torques and drags.

Torque and drag models are also used in real time to detect potential drilling problems at an early stage before these problems cause serious damage. This is done by comparing hook-load measurements in real time to the calculated values. Deviations from the values in the models indicate a problem down-hole. The problem might be due to key seating, differential sticking and cuttings bed accumulation. Other factors such as ECD, standpipe pressure, and pit volume must be checked to evaluate the nature of the problem. In order to obtain the best results, real time surveys should update the model in order to include deviations from planned well trajectory and directional drilling errors. Torque and drag models are the best tool available for monitoring hole conditions.

In real time it is also possible to back-calculate the friction factor from the measured hook-load by iterating until a match between the measured value and the model (Lesage 1988) is found.

A plot of calculated friction factors versus depth is then used to identify downhole problems. This can also be calculated during drilling if the downhole weight on the bit and the downhole torque on bit is present. Torque and drag models are steady state models, which means that the calculations are only made for string movement in a steady manner and sudden transient effects are not incorporated into the calculations.

In post drilling, a detailed analysis can be helpful in revealing the true cause of problems that were previously unexplainable. The post drilling analysis allows for changes to operational procedures to be made, so that problems can be avoided when drilling the next well.

The measured data can be used to yield a better understanding and allow for a better planning of the next well. Post analysis may also lead to a more accurate friction factor, by including local information such as formation lithology, permeability, and mud properties. The gained information can be used to evaluate improved well trajectories and kick-off point depths, as well as correcting casing setting depths, in order to avoid encountering hole problems in the evaluated wells.

3.2   Uses of Torque and Drag Modeling

- Trajectory design to minimize torque and drag forces

- Determining hole condition to determine if problems are arising

- Drill string design to reduce torque and drag

- Monitoring hole cleaning in real time

- Monitoring friction when running casing

- Determine the onset of drill pipe buckling

- Determine the possibility of reciprocating casing during cementing

- Providing lateral load inputs for casing wear models

- An aid in determining if a changes to the mud is necessary

- Calculating WOB in highly inclined wells with high frictional drag

- Determining if drill string torque limits may be exceeded

- Aid in making strategic decisions on mud systems

3.3   Soft-String Versus Stiff-String Model

The soft string and the stiff string models are two different mathematical models which are used for torque and drag analysis. They were developed to describe the mechanical behavior of the drill string inside the borehole and they have their own theoretical background and assumptions. The soft string model is widely used in the industry and it assumes that the drill string has a continuous surface contact area with the wellbore as it deforms to the shape of the wellbore.

The model ignores the bending stiffness in the drill string and borehole clearance. For a smooth well geometry, the model has a good approximation of forces and contact loads.

In some cases, due to the friction force generated by the rotation, the string climbs on the wellbore wall and will cause the contact force to be less than if the pipe lies on the low side of the wellbore, which is the main soft string model assumption. Therefore, the soft string model cannot predict such diverse positing which in some cases will lead to errors in torque and drag prediction due to the drill string position on the side, high, right, or left side of the wellbore depending on the section and operation.

The stiff sting model takes into account the drill string stiffness in the wellbore and the annulus clearance. The model calculates all the contact points between the drill string and the wellbore and the drill string reacts naturally to the forces and moments. Therefore, the model predicts more realistically the side forces along the drill string, which helps to determine torque and drag losses and better match with the actual

measurements. But the stiff string model is not recommended for real time torque and drag monitoring because of the long time required for its application [9] [10].

Both soft and stiff string models show similar results over the smooth wellbore geometry but they give different predictions in a tortuous wellbore.

3.4   The Soft-String Model

Considering an object of weight W is resting on a horizontal plane:
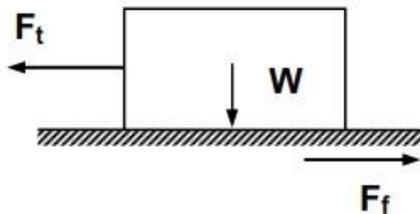
Figure 3.1 Forces acting on an object resting on a horizontal plane

In order to slide the object a force Ft must be exerted to overcome the force of friction Ff between the object and the plane surface.

The magnitude of the frictional force is:

$$Ff = \mu \, W$$

Where:

Ff = frictional force (lb)

μ = dimensionless coefficient of friction, a constant that depends on the roughness of the object and plane surface, determined experimentally

W = normal force acting perpendicular to the surface (lb)

Therefore, the force Ft (Drag Force) required to slide the object should be slightly greater than Ff (friction Force).

3.4.1 For Inclined Straight Hole Section

Considering a straight section of drill pipe in a wellbore inclined at an angle:
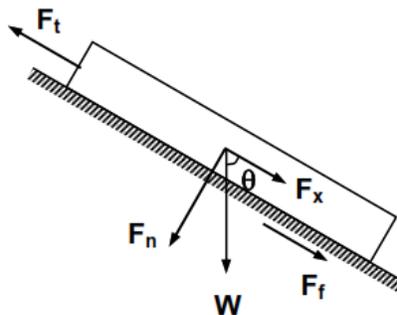
Figure 3.2 Forces acting on an object resting on an inclined straight plane

The buoyed weight of the drill pipe W is acting vertically downward and can be resolved into two forces:

Fn – normal force acting perpendicular to the hole:

$$Fn = W \sin \theta$$

Fx – the weight component acting parallel to the hole axis:

$$Fx = W \cos \theta$$

The frictional or drag force Ff is the normal force multiplied by the coefficient of friction:

$$Ff = Fn\ \mu = W\ \mu\ \sin\theta$$

The force Ft required to move the drill pipe is determined by making a force balance

$$Ft = Fx \pm Ff$$

$$Ft = W\cos\theta \pm W\ \mu\ \sin\theta$$

The frictional force or drag always acts in the opposite direction of the pulling force Ft. Therefore, the sign is negative (-) if the drill pipe is lowered into the hole, and positive (+) when the drill pipe is pulled out of the hole.

3.4.2 For Curved Hole Section

In a curved section of the wellbore where inclination and azimuth change across the section, the calculation of the drag force is more difficult.
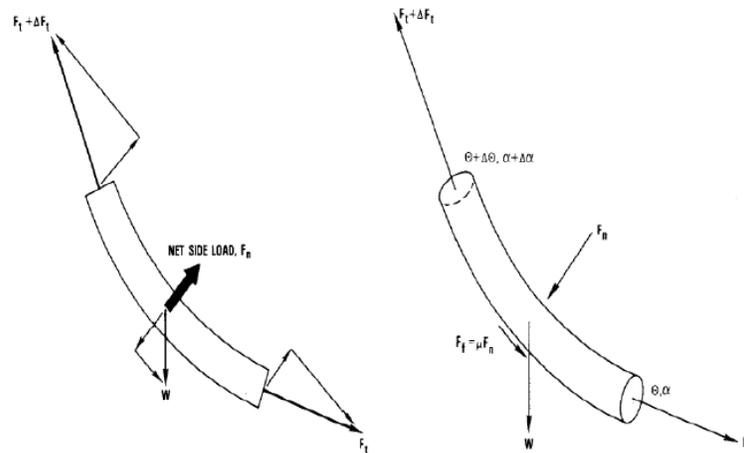
Figure 3.3 Forces acting on a drill string element, illustrating the normal force, friction and changes in inclination and azimuth [4]

In 1984, C.A. Johancsik presented the pioneer friction analysis model. In his model both torque and drag were assumed to be caused entirely by sliding friction between drillstring and borehole wall. Other sources of torque and drag like friction due to fluid and cuttings, static friction, and piston forces were not considered [4].

The sliding friction coefficient is the ratio of the friction force to the normal contact force.

The normal force is given by:

$$Fn = \sqrt{(Ft\Delta a\sin\theta)^2 + (Ft\Delta\theta + W\sin\theta)^2}$$

Where:

Fn = The normal force at the lower end of the string element (Ib)

Ft = The tensile force at the lower end of the string element (Ib)

Δa = The change in azimuth angle over the string element (radians)

θ = The inclination at the lower end of the string element (radians)

$\Delta\theta$ = The change in inclination angle over the string element (radians)

W = The buoyed weight of the string element (lb)

The normal force is then used to derive the equation for tension increments:

$$\Delta Ft = W\cos\theta \pm \mu Fn$$

Where μ is the friction coefficient, the positive sign (+) is used when hoisting, and the negative sign (-) is used when lowering the drill string. In addition, the torsion increment is calculated as:

$$\Delta M = \mu\ Fn\ r$$

Where:

ΔM= The increment in torque across the string element (ft.Ib)

r = The radius of the string element (ft)

The model assumes that the drill string is consisted of short elements joined by connections that transmit torsion, tension, and compression, but not the bending moment.

The basic equations of friction are applied to each segment with calculations starting from the bottom of the drill string and continuing upward to the surface. Each short interval of drill string contributes increments of torque, drag, and weight. Forces and torque values are added to produce the cumulative loads on the string. Initial conditions are specified at the bit and the inputs are the weight on the bit and bit torque values for drilling operations.

3.5 Side Forces

The weight of the drill string acting on the wellbore is a major contributor to side forces and to the magnitude of the normal force against the wellbore. As such, heavier drill strings induce greater side forces against wellbores. Therefore, it is important to minimize the weight of the drill string within safe limits.
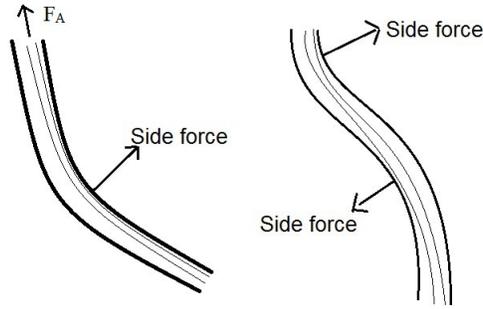
Figure 3.4 Side forces on a drill pipe

Side forces created by tension typically only occur with doglegs. In build sections, the direction of pipe movement affects the direction of side forces. When moving down, the drill string will be lying on the low side – therefore, the effect of tensile load is reduced and the resultant side force is in the direction of the weight component. When moving up or tripping out, the drill string will be in contact with the high side. Therefore the effect of tensile load is increased and the resultant side force will be in the direction of the tensile component. In drop sections, regardless of whether the drill string is tripping out or running in the hole, the drill string will be lying on the low side of the wellbore. Therefore, the resultant force will always act on the low side.

3.6 Buoyancy Factor

Buoyancy is an upward force exerted by the drilling fluid against the weight of the drill string. In the well filled with drilling fluid, the weight of the drill string is the weight in the air minus the mud weight that the steel in the string displaces. This phenomenon is known as Archimedes' principle. The buoyancy factor can be more conveniently defined as:

$$\beta = 1 - \frac{\rho \ (\text{mud})}{\rho \ (\text{string})}$$

If there are different densities of fluids inside and outside the pipe – for example, during tripping in, during displacement of mud to new mud, and while cementing, the buoyancy factor can be defined as:

$$\beta = 1 - \frac{\rho o \, Ao - \rho i \, Ai}{\rho \, (\text{string})(Ao - Ai)}$$

Where:

β = Buoyancy factor

ρ (mud) = Density of drilling mud

ρ (string) = Density of drill string (usually the density of steel)

ρo = Density of fluid outside the pipe

ρi = Density of fluid inside the pipe

Ao = Outer cross sectional area

Ai = Inner cross sectional area

A heavy mud will decrease the effective weight of the drill string and thus decrease the side force and the load from friction and torque. However, a heavy mud has heavier particles, which could lead to less lubricity and therefore higher friction.

3.7 Friction

Contact friction, such as when two relatively smooth solid bodies slide against each other, will be independent of the speed at which the two bodies slide and independent of the contact area. This applies only for soft string models under consideration but the friction force will be proportional to the contact force of the sliding surfaces. A friction coefficient μ is the ratio of the friction force to the normal force. In order to find the normal force in an inclined plane, consider the schematics shown in Figure 3.5.

$$\mu = \frac{Ff}{Fn}$$
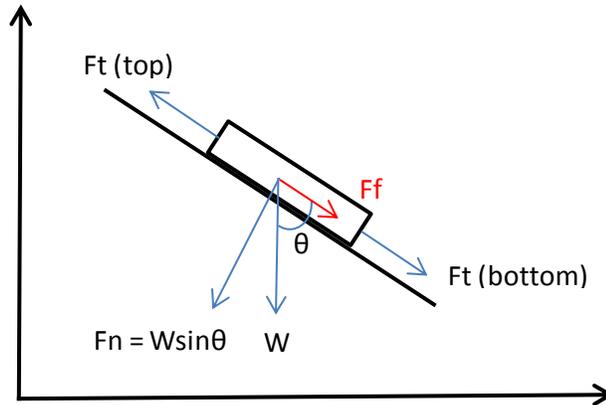
Figure 3.5 Forces on an object sliding on an inclined plane

Where:

μ= friction coefficient

Ff = Friction force

Fn = Normal force

Ft = Tensile force

W = weight of the segment

θ = Inclination angle
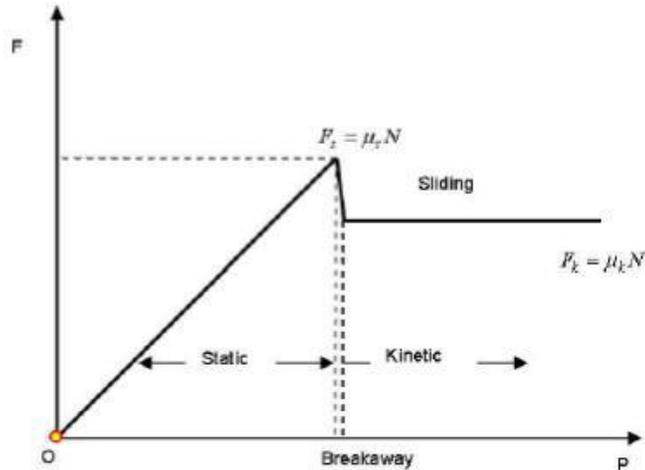
Figure 3.6 Static and dynamic friction

The friction factor is a key parameter in torque and drag modeling because it characterizes the surface-to-surface interaction, which is the heart of the model. The friction factor applicable to any situation is a function of many things, including fluid type, composition, lubricity, formation type, casing and tool joint material, and roughness. When significant portions of both cased and open hole exist, it may be necessary to use more than one friction factor, usually two - one for open-hole, and one for cased hole. Generally the friction factors selected are 0.2 and 0.3 for cased and open-hole respectively. But in real time operations these friction factors are calibrated regularly during the operations.

3.8 Buckling

Buckling is a very important issue in torque and drag calculations and it occurs when the drill string is in compression. Buckling increases the contact surface area between the drill string and the wellbore, which increases side forces. Sinusoidal buckling occurs first; it begins when axial compression increases in the drill string and there is a string snake phenomenon along the wellbore. As the axial compression continues to increase, the buckling will change into a helix drill string, a phenomenon called helical buckling.

Sinusoidal buckling can generally be tolerated while helical buckling should be avoided, because helically buckled strings create additional drag, which could lead to a "lock up" situation. This means that after the drill string is released from the derrick, the entire drill string will be supported by wellbore friction instead of by the bit force.
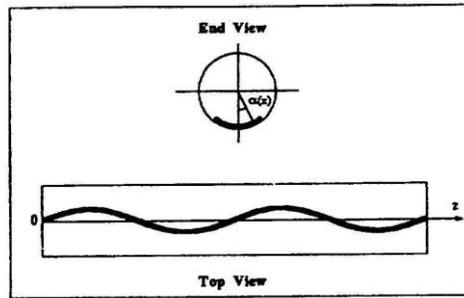
Figure 3.7 Sinusoidal buckling of the pipe in a horizontal wellbore [11]
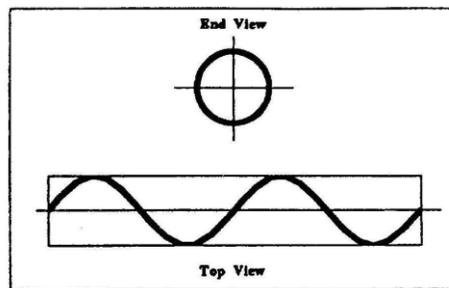
Figure 3.8 Helical buckling of the pipe in a horizontal wellbore [11]

3.8.1 Buckling in a Deviation Wellbore

A long pipe in a wellbore will be buckled into a sinusoid along the lower side of the hole at an axial compressive force of Wu and Juvkam-Wold's model (1991):

$$Fs = 2\sqrt{\frac{EIW\sin\theta}{r}}$$

The helical buckling is given by:

$$Fh = (2\sqrt{2} - 1)\, Fs$$

Where:

Fs = Sinusoidal buckling

Fh = Helical buckling

E = Young's modulus of elasticity

W = Buoyed weight of the string element

I = Moment of inertial component

θ = Wellbore inclination

r = Radial clearance between the wellbore and drill string (tool joint)

F = Compressive axial force

3.8.2 Buckling in a Vertical Well

In a vertical section, the tube is easily buckled, which adds some considerable axial friction force. The critical load for sinusoidal buckling, presented by Wu and Juvkam-Wold, (1993) [12] is:

$$Fs = 2.55\, (EIW^2)^{\frac{1}{3}}$$

The helical buckling load is about 2.2 times as large as the sinusoidal buckling load in the vertical wellbore as presented by Wu and Juvkam-Wold, (1993):

$$Fh = 2.18\, Fs$$

4 TORQUE AND DRAG MODELING

4.1 Input Data

The torque and drag model is constructed for the 12 ¼" section, which starts from a depth (1100m) which is the casing seat of the previous casing of 13 3/8" until depth (2700m), which is the TD of the 12 ¼" section. The section is vertical, with minor deviations according to the survey data.

Thus, the model will simulate the forces acting on the drill string from the surface (depth equal to zero, as the top drive system is ignored in the calculations) through the 13 3/8" cased hole until (1100m), then continuing through the 12 ¼" open hole section until (2700m).

Mud weight of 10.5 ppg was used in the model, as in the actual drilling data. The friction factor is assumed to be 0.25 for the cased hole section and 0.35 for the open hole section based on calibrations from nearby wells. Taking into account that the weakest point in the drill string that will have the highest load is the last string of the drill pipe in the surface, the maximum allowable tension is 436 KIbs and the maximum make-up torque that should not be reached is 30.7 ft.Ibs.

The drill string is divided into segments of "1 meter", and calculations of tension forces have been done for each segment starting from the bottom and summed up to the top.

4.1.1 Drill String Data

Table 4.1 12 ¼" Bottom hole assembly (BHA)

12.1/4" Hole assembly	Body OD	Connections	Supplier
12-1/4" Bit PDC SMITH Bit XS616 Nozzles: 6x14	12.250	6.625 REG Pin	SMITH
Power-V – PD900 x6 w/ 12-1/8" stab	9.125	6.625 REG B X 6.625 REG B	SLB
8-1/4" Collar	8.250	6.625 REG P X 6.625 REG B	Rig Contractor
12-1/8" Stabilizer	12.125	6.625 REG P X 6.625 REG B	SinoGulf
Float sub (with non-ported float)	8.5	6.625 REG P X 6.625 REG B	SinoGulf
WINC	8.000	6.625 REG P X 6.625 REG B	MidWest
10 X 8-1/4" Collar	8.250	6.625 REG P X 6.625 REG B	Rig Contractor
Dogleg reamer (DLR)	8.250	6.625 REG P X 6.625 REG B	NOV
3 X 8-1/4" Collar	8.250	6.625 REG P X 6.625 REG B	Rig Contractor
8" Hydro mechanical Drilling Jar	8.000	6.625 REG P X 6.625 REG B	SinoGulf
3 X 8-1/4" Collar	8.250	6.625 REG P X 6.625 REG B	Rig Contractor
Crossover	8.250	6.625 REG P X 4.5 NC50 (4 1/2 IF) B	Rental
9 X 6-3/4" Collar	6.750	NC50 P X B	Rig Contractor
15 X 5" HWDP	5.000	NC50 P X B	Rig Contractor

The drill string is modeled for the Drill Pipe (DP), Heavy Weight Drill Pipe (HWDP) and Drill Collars (DC), therefore, the BHA is assumed to be consists of DP, HWDP and DC only.

Table 4.2 Pipes characteristics

	Length (m)	Weight (Ibs/ft)	OD (inch)	ID (inch)	Tool Joint OD (inch)	Tensile Strength (Klbs)	Make up Torque (ft-KIbs)
Drill pipe	2368	19.5	5	4.276	6.625	436	30.7
HWDP	156	49.8	5	3	6.625	691	33.9
Drill collar	177	158.7	8.25	2.813	8.25	1856	52.1

4.1.2 Hole Sections Information

Table 4.3 Hole sections details

	Length (m)	OD (inch)	ID (inch)	Friction factor	Mud density (ppg)
Casing	1100	13 3/8"	12.62	0.25	10.5
Open hole	1600	N/A	12.25	0.35	10.5

4.1.3 Caliper log data

A caliper log is a well logging tool that provides a continuous measurement of the size and shape of a borehole along its depth; it is used for the open hole inside diameter in the calculations in order to give more accurate results. For the cased hole section, the inside diameter is fixed [13].
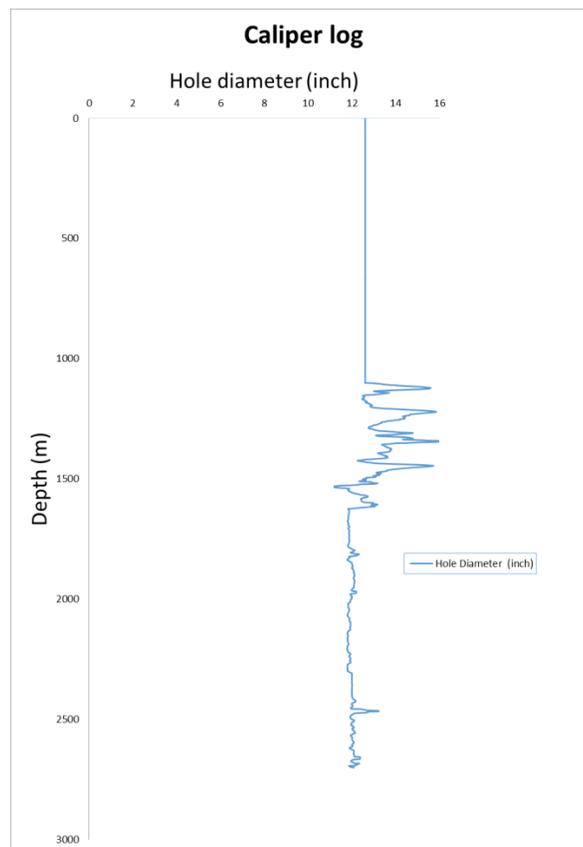
Figure 4.1 Hole diameter from the caliper log

4.1.4 Survey Data

Survey data represents the well path and surveys are taken from MWD measurements. An inclination of 0° would be true vertical, and an inclination of 90° would be horizontal. Azimuth is the angle, measured in degrees, of the horizontal component of the borehole or survey-instrument axis from a known north reference. This reference is true north, magnetic north, or grid north, and is measured clockwise by convention. It is important to highlight that all the angles should be converted to radians in order to be used in the model [14].
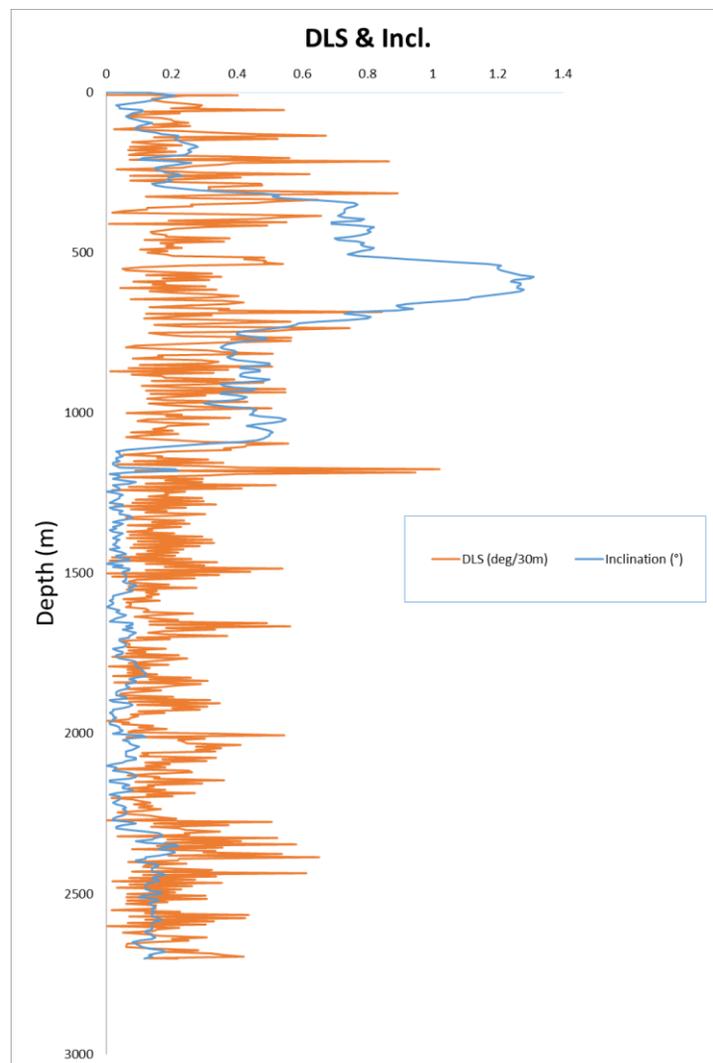
Figure 4.2 Inclination and DLS versus measured depth
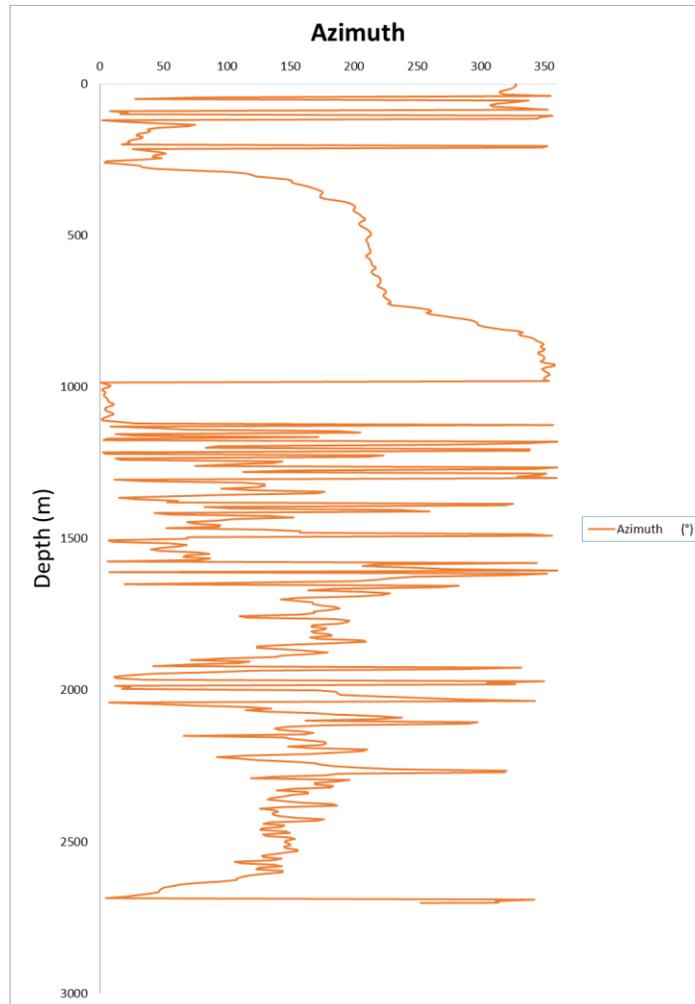
Figure 4.3 Azimuth versus measured depth

4.2 Model Construction

4.2.1 Calculation of Buoyed Weight

The buoyancy factor is calculated using a density of 65.5 ppg for steel and 10.5 ppg for the drilling mud:

$$\beta = 1 - \frac{\rho \text{ (mud)}}{\rho \text{ (string)}}$$

Where:

β = Buoyancy factor

ρ (mud) = Density of drilling mud

ρ (string) = Density of drill string (density of steel)

Then the buoyed weight of each element is calculated:

$$\text{Buoyed weight} = \text{Actual weight} \times \beta$$

The nominal weight of the drill pipe used is 19.5 Ib/ft; for HWDP it is 49.3 Ib/ft; and for the drill collar it is 147.22 Ib/ft. It is important to convert the one meter element to feet in order to multiply it by the buoyed weight from the above equation to obtain the buoyed weight for each element.

4.2.2 Calculation of Axial Loads

First, the tension at the bottom of each element is calculated:

$$F_t = W \cos\theta$$

Where:

F_t = The tensile force at the lower end of the string element (Ib)

W = Buoyed weight of the string element (Ib)

θ = Inclination at the lower end of string element (radians)

The tension force of each element, summed up to the elements above it, starting from the bottom, is used in normal force calculations. In other words, the tension force at the lower end of an element will be the sum of tension forces of all elements below it. This tensional incensement is called the free rotation weight or off bottom weight of the drill string.

Next, the normal force for each element is calculated:

$$Fn = \sqrt{(Ft\Delta a\sin\theta)^2 + (Ft\Delta\theta + W\sin\theta)^2}$$

Where:

Fn = The normal force at the lower end of the string element (Ib)

Ft = The tensile force at the lower end of the string element (Ib)

Δa = The change in azimuth angle over the string element (radians)

θ = The inclination at the lower end of the string element (radians)

$\Delta\theta$ = The change in inclination angle over the string element (radians)

W = The buoyed weight of the string element (lb)

The frictional force is then calculated for each element:

$$Ff = \mu\, Fn$$

Where:

Ff = frictional force (lb)

μ = coefficient of friction, assumed to be 0.25 for cased hole section and 0.35 for open hole section

For upward movement of the drill string, the frictional force is acting downwards; therefore, the frictional force must be added to the tensional force. This confirms that the measured weight of the drill string on the surface while pulling out of the hole is greater than the actual weight of the string.

The tensional force is calculated as:

$$Ft = Ft + Ff$$

The above tensional force for each element is separate. In order to calculate the cumulative tensional loads along the drill string, tensions for every element must be added to the element above. For example, the tensional load at the lower end of an element is the total load of all elements below this element.

The same scenario is applied for the case of running in the hole, but with a negative sign (-). As the drill string moves downward, the friction acts upward; therefore, the frictional force is subtracted from the tensional load and the measured weight of the drill string at the surface while running in the hole appears to be less than the actual weight of the string.

$$Ft = Ft - Ff$$

4.2.3   Calculation of Torsional Loads

The frictional torque at each element is calculated by multiplying the frictional force by the radius of the drill string; the tool joint radius is usually considered.

$$M = Ff \ r$$

Then the torsion increment is calculated by adding the torque of each element to the element above starting from the bottom – this is called the off bottom torque.

To calculate the torque (on bottom), the torque on the bit must be added. Therefore, the torsion increment is calculated starting from the torque on the bit.

Torque at the surface = Torque on the bit + M1 (last element in the bottom) + M2 + . . . , + Mn (First element from the surface).

Furthermore, for (on bottom) torque calculation, the weight on the bit is subtracted from the tension increment. To calculate the torque while running in the hole, the tensional force of RIH is used, and the tensional force of POOH is used for pulling out of hole torque.

4.2.4 Calculation of buckling loads

The sinusoidal and helical buckling is calculated as [11]:

$$Fs = 2\sqrt{\frac{EIWsin\theta}{r}}$$

$$Fh = (2\sqrt{2} - 1)\ Fs$$

Where:

Fs = Sinusoidal buckling (Ib)

Fh = Helical buckling, (Ib)

E = Young's modulus of elasticity (psi)

W = Buoyed weight of the string element (lb)

I = Moment of inertial component

θ = Inclination at the lower end of string element

r = Radial clearance between the wellbore and drill string (tool joint) (ft)

5   CALCULATION OF TORQUE ON BIT USING PAYZONE SIMULATOR

5.1   PayZone Drilling Predictive Simulator

The PayZone Drilling Simulator is a PC based simulator that can be used for training as well as planning and optimizing field operations. It is built around a drilling mechanics model that predicts the rate of penetration and rate of wear of a drill bit as a function of the bit, the rock being drilled and a set of operating parameters. The software is able to carry out the following operations: Drilling, hydraulics optimization, directional drilling, dealing with kicks and losses, handling hole stability problems, logging, casing and cementing [15].

The heart of the program is a drilling mechanics algorithm that calculates the state of wear of a drill bit and its resulting rate of penetration as a function of the type of drill bit, the operating parameters and the nature of the rocks being penetrated.
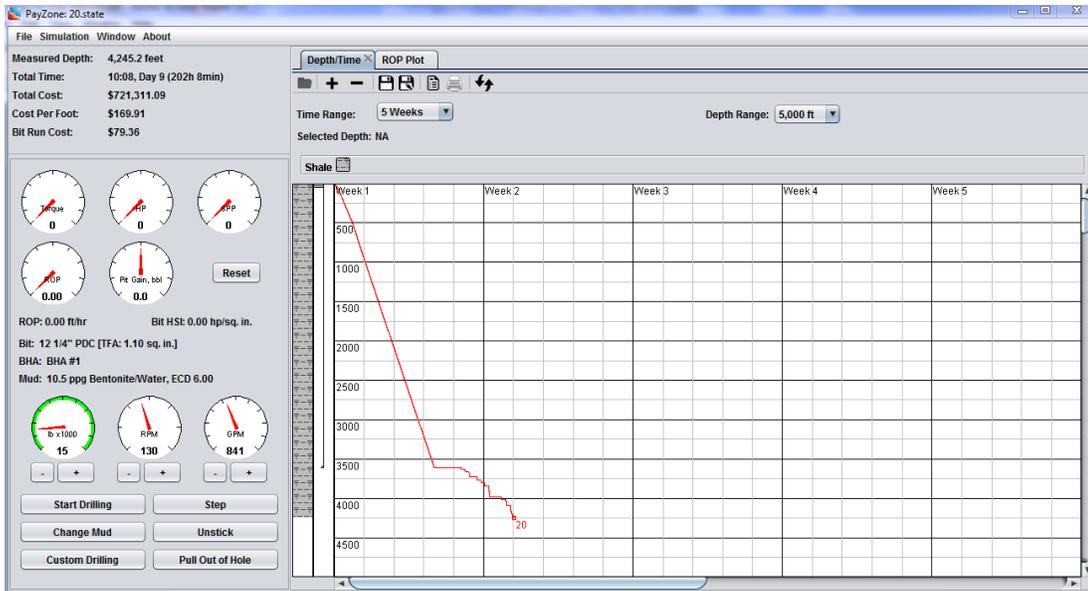
Figure 5.1 Payzone simulator

PayZone functions are divided between nine different editors. Before drilling begins, some information is assembled in order for the simulator to operate. The simulator is built up of contributions from six primary editors (lithology, drill bits, BHAs, muds, casings and settings).The output is then combined by the State Editor into a State file. The State file is the data source from which the simulator runs its calculation [15].

5.2   ROP Modeling and Prediction

Researches has demonstrated that rate of penetration (ROP) depends on two group of parameters: drilling rig and formation parameters. The drilling rig parameters includes the following: weight on bit (WOB), bit rotational speed (RPM), hydraulic parameters (mud flow rate, mud rheology and mud density), bit and bit condition. All these parameters should be identified [16].

From the formation group the most essential parameters affecting penetration rate are: local stresses, rock compaction, fluid pore pressure and mineralogical content which is related strongly to lithology of subsurface formations [16].

PayZone simulator enables the prediction of ROP using a mathematical model; the model is developed based on Teale's concept of mechanical specific energy [17]. The main features of the model predicting rate of penetration are given as [16]:

$$ROP = (flow\_factor)(c)(aggressivity)(RPM)(tooth\_length)(G)$$

$$G = 1 - \exp\left[-\left(\frac{WOB}{UCS}\right)^{curv}\left(\frac{12}{D^{2.5}\ (0.4 * tooth\_length)}\right)\right]$$

Where:

ROP = Penetration rate

RPM = Rotary speed

tooth_length = The average length of the bit teeth

UCS = Unconfined compressive strength of the rock

D = Bit diameter

WOB = Applied weight on bit

C = Constant

aggressivity = Formation and bit characteristic constant ranging between 20% and 100% and normally is given the value of 35%

curv = Formation-bit interaction constant and it is usually given the value of 1.5

flow_factor = Constant, ranging between 50% and 100% and defines the capability of the system to adequately clean the bit front by the cuttings

A similar rock-bit interaction model, with adjustable parameters, is the one that has been presented by Teale [17]. In this model the concept of specific energy is introduced. This concept predicts the energy required by the rig to drill a unit volume

of rock. This model has been used by many researchers and practitioners in the past as shown below:

$$\text{ROP} = \frac{(8)(\text{RPM})(\mu D)(\frac{\text{WOB}}{\text{Abit}})}{\frac{\text{UCS}}{\text{eff}} - \frac{\text{WOB}}{\text{Abit}}}$$

Where:

Abit = Bit face area

μ = The coefficient of friction between drill string and formation, converting applied WOB to torque

eff = The efficiency of transmitting the rock destruction power of the drilling rig to the rock

It has been shown that predictions from both models are essentially the same and lead to the same results [18]. Thus, the values of UCS can be used to estimate rock drillability [19].

5.3   Constructing the Lithology

The Lithology Editor section in the software enables the user to build a sequence of rock layers that can be drilled by the simulator. This sequence is known as a lithology or litho. Each layer can be given its own properties (thickness, mineralogy, strength, abrasivity, log properties… etc.) which will be used by the simulator to generate the drilling response.

User can build the lithology by importing the LAS file. LAS files contain columns of data in standard text format. every LAS file begins with ~C (~Curve Information), that associates the title of each column of data with the corresponding measurement. The LAS Converter identifies the title of the column and assigns the data in that column to the appropriate position in the PayZone Litho. Titles currently identified are converted as shown in the table.

```
LAS column title  PayZone parameter
DEPT              depth
GR                gamma ray emission rate
ILD               resistivity (Induction Log Deep)
NPHI              porosity (inactive)
PORO              porosity
SP                spontaneous potential
RHOB              density
DT                compressive wave sonic velocity
ST                shear wave sonic velocity
UCS               unconfined compressive strength
ABR               rock abrasivity
FRICANG           angle of internal friction
PPRE              pore pressure gradient
FRAC              fracture pressure gradient
V_CO              volume fraction of coal
V_DO              volume fraction of dolomite
V_LS              volume fraction of limestone
V_HS              volume fraction of hard sandstone
V_SS              volume fraction of soft sandstone
V_SH              volume fraction of shale
V_TF              volume fraction of tuff
```

Figure 5.2 LAS file parameters - PayZone Parameters mapping

As a pre-processing step, LAS data are analyzed before assigning them to the litho section. And some titles have been changed to match with the software titles. One of these changes is a missing rock unconfined compressive strength (UCS). This parameter is calculated and then added to the LAS file before importing into PayZone. UCS is estimated using the formula:

$$UCS = 72.5 \text{ x } ((304.8/ DT\_C) \, 3 + RHO \text{ x } (304.8/ DT\_C) \, 2)$$

Where:

UCS: Unconfined compressive strength (psi)

DT_C: Sonic data in the form of slowness (microseconds/ft)

RHO: bulk density (g/cc)

```
#LOGNAME          .UNIT      LOG_ID
#_____
MD                .m
DT                .us/ft
GR                .gAPI
PORO              .v/v
ILD               .ohm.m
RHOB              .g/cm3
UCS               .psi
```

Figure 5.3 LAS file parameters

Lithology Editor

File Edit Window About

Layer #	Layer Depth	Layer Thickness	Rock Type	Rock Strength	Rock Abra	Pore Press.	Frac. Grad.	Log Por.	Log Res.	Log Gamm	Fluid Type
9057	7,936.0	0.5	Shale	8.0	1.0	8.00	18.00	26.0	6.40	73.3	-
9058	7,936.5	0.5	Shale	7.7	1.0	8.00	18.00	29.1	3.95	83.0	-
9059	7,937.0	0.5	Shale	7.5	1.0	8.00	18.00	33.1	3.47	94.6	-
9060	7,937.5	0.5	Shale	7.6	1.0	8.00	18.00	32.3	3.80	103.5	-
9061	7,938.0	0.5	Shale	7.7	1.0	8.00	18.00	31.3	3.32	109.7	-
9062	7,938.5	0.5	Shale	8.1	1.0	8.00	18.00	30.6	3.45	115.4	-
9063	7,939.0	0.5	Shale	8.7	1.0	8.00	18.00	30.9	3.72	110.5	-
9064	7,939.5	0.5	Shale	9.4	1.0	8.00	18.00	29.4	4.16	96.3	-
9065	7,940.0	0.5	Shale	10.4	1.0	8.00	18.00	26.0	8.00	83.0	-
9066	7,940.5	0.5	Shale	12.0	1.0	8.00	18.00	24.4	9.74	71.7	-
9067	7,941.0	0.5	Shale	13.2	1.0	8.00	18.00	21.5	9.67	72.0	-
9068	7,941.5	0.5	Shale	13.8	1.0	8.00	18.00	20.7	9.02	67.9	-
9069	7,942.0	0.5	Shale	14.9	1.0	8.00	18.00	18.8	15.09	67.7	-
9070	7,942.5	0.5	Shale	16.7	1.0	8.00	18.00	17.2	21.52	65.0	-
9071	7,943.0	0.5	Shale	16.9	1.0	8.00	18.00	16.2	23.67	58.9	-
9072	7,943.5	0.5	Shale	17.2	1.0	8.00	18.00	14.5	37.17	56.2	-
9073	7,944.0	0.5	Shale	17.2	1.0	8.00	18.00	13.9	50.09	51.3	-
9074	7,944.5	0.5	Shale	17.1	1.0	8.00	18.00	13.1	81.93	48.4	-
9075	7,945.0	0.5	Shale	16.9	1.0	8.00	18.00	12.4	83.92	45.9	-
9076	7,945.5	0.5	Shale	16.2	1.0	8.00	18.00	13.2	26.93	49.8	-
9077	7,946.0	0.5	Shale	16.1	1.0	8.00	18.00	15.4	12.96	55.0	-
9078	7,946.5	0.5	Shale	15.7	1.0	8.00	18.00	18.3	14.55	57.0	-
9079	7,947.0	0.5	Shale	15.3	1.0	8.00	18.00	19.2	16.65	58.3	-
9080	7,947.5	0.5	Shale	15.2	1.0	8.00	18.00	18.3	17.64	60.8	-
9081	7,948.0	0.5	Shale	15.5	1.0	8.00	18.00	18.1	21.16	60.4	-
9082	7,948.5	0.5	Shale	15.9	1.0	8.00	18.00	17.7	25.21	55.6	-
9083	7,949.0	0.5	Shale	15.5	1.0	8.00	18.00	17.1	27.89	50.4	-
9084	7,949.5	0.5	Shale	15.4	1.0	8.00	18.00	17.3	19.33	53.3	-
9085	7,950.0	0.5	Shale	15.6	1.0	8.00	18.00	17.1	13.19	55.4	-
9086	7,950.5	0.5	Shale	15.8	1.0	8.00	18.00	16.7	25.12	55.0	-
9087	7,951.0	0.5	Shale	16.0	1.0	8.00	18.00	15.6	36.60	52.0	-
9088	7,951.5	0.5	Shale	16.4	1.0	8.00	18.00	15.9	19.82	55.4	-

Layers: 17465, Total Depth: 12,140.5

[New Layer Above] [New Layer Below] [Delete Layer] [Edit Layer] [Edit Surface]

Figure 5.4 Lithology data – After importing LAS file into PayZone
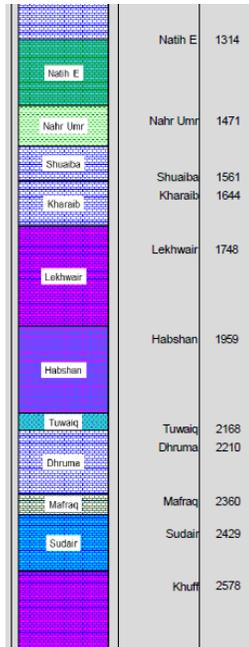
Figure 5.5 Actual section lithology

5.4 Drilling the 12 ¼" section

Drilling is simulated using the input parameters from actual drilling data:

WOB: Weight on bit, kIbs

RPM: Rotary speed, revolution per minute

GPM: Flow rate, gallon per minute

TFA: Nozzles total flow area, inche²

MUD WEIGHT: Pounds per gallon (ppg)
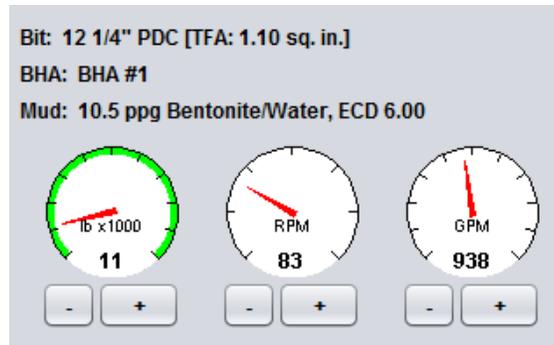
Figure 5.6 Drilling control panel 1

Before the drilling starts, BHA and drill bit are selected. By clicking on run in hole and then start drilling, the simulator will make drilling through the lithology using the provided input parameters to calculate:

Torque: Down-hole Torque (ft-lb)

SPP: Standpipe pressure (psi)

ROP: Rate of penetration (ft/hr)

ECD: Equivalent circulating density (ppg)

Bit HSI: Bit Hydraulic Horsepower

Pit Gain: mud pit gain (bbl)

HP: Mud Pump Horsepower
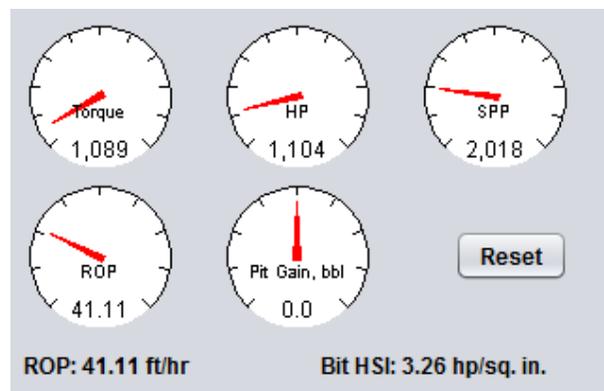
Figure 5.7 Drilling control panel 2

5.5   Tuning

In The first simulation run, the predicted ROP does not match the real ROP. This is caused by uncertainty in bit characteristics and rock properties. Therefore, ROP factor is selected as an uncertain variable and varied within an acceptable range. Until the best match of predicted and real ROP is reached. After matching the ROP with up to 10% error, the predicted torque is used as a best estimated torque.

5.6   Torque values from PayZone

After simulating the drilling process and tuning for the best ROP matching. The torque values are exported to be added to the frictional torque calculated from the frictional model, then compared with the actual cumulative torque.
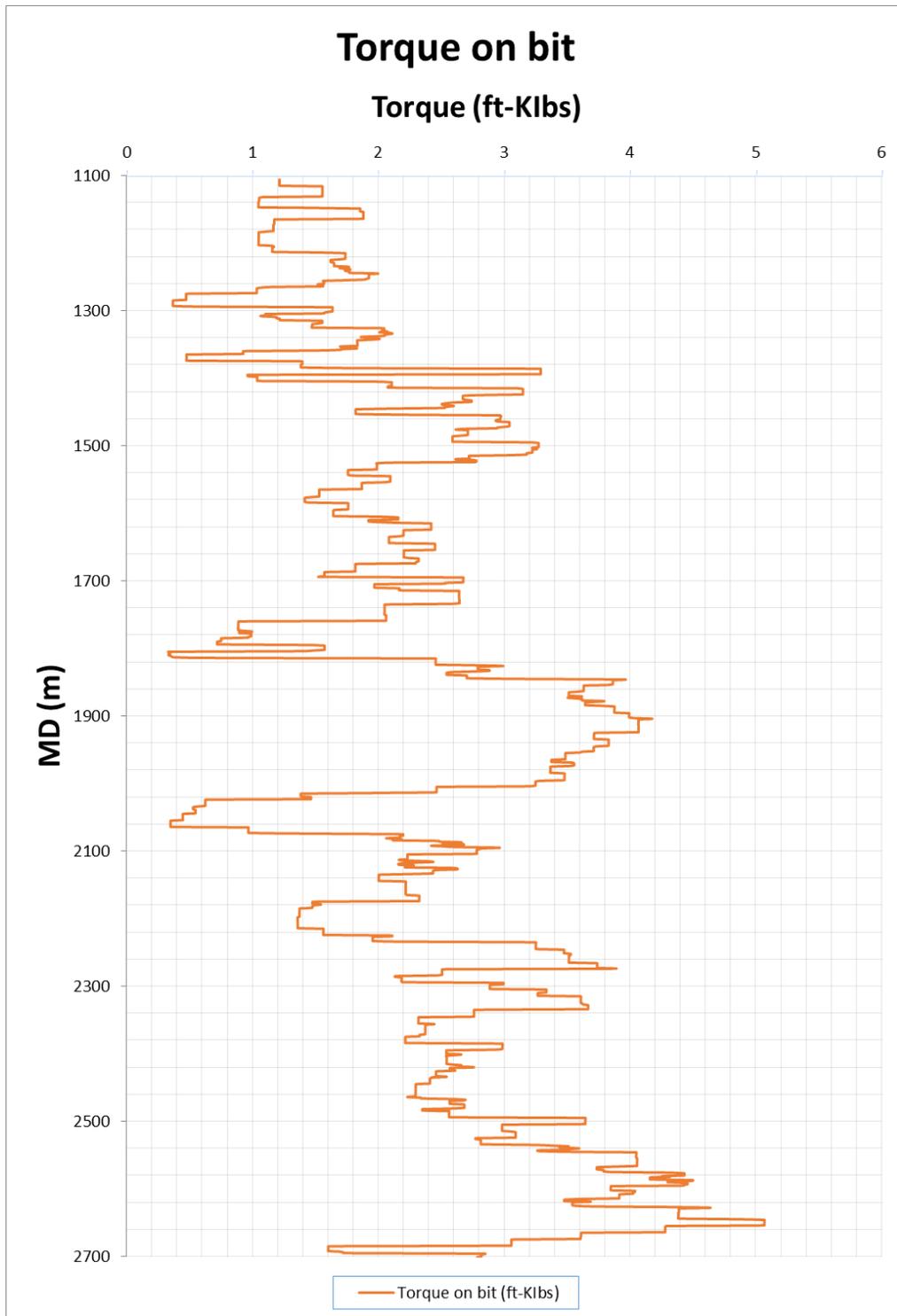
Figure 5.8 Torque values from PayZone

6 RESULTS AND DISCUSSIONS

The first part of this chapter deals with results of the constructed Torque and Drag model analysis that applied on the drill string for the 12 ¼" section TD. The main results are:

• The tension along the drill string.

• The frictional toque long the drill string.

• Hook-load while tripping.

• The frictional torque while tripping.

The second part deals with the hook-load comparison between actual data and the hook-load calculated from the Torque and Drag model.

The third part deals with torque results from PayZone simulator, the frictional torque from the Torque and Drag model. Then both results are compared to the actual cumulative torque for the same section.

6.1 The Tension Along the Drill String

Using the Torque and Drag model, loads have been calculated for every meter of the drill string. The drill string length is 2700 m, this is for the case of drill bit is at depth of 2700m. The top part of the drill string (surface – 1100m) is located inside the 13 3/8" casing and the lower part (1100m – 2700m) is located in the 12 ¼" open hole section.

The calculations have been done for four scenarios:

• The drill string tension/load/weight while the bit is off bottom i.e. free rotating weight with no axial movement.

- The drill string weight while the bit is on bottom with applying weight of bit of 50 KIbs. It is obvious that the loads on the drill string are less in this case because most of the stress is exerted upon the bit.

- The drill string weight while running in the hole. These weights are less than the free rotating weight due to the frictional forces which acting against the string motion, which means acting upwards, this approves the scenario when the hook-load is less than the actual weight of the drill string when monitored from the weight indicator at the surface while tripping in the hole which is discussed in the literature.

- The drill string weight while pulling out of the hole, this is opposite to the previous case, the weights are more than the actual due to the frictional forced which acts against the drill string motion, which means acting downwards, therefore, it adds loads to the string. The hook-load shows more than the actual on the weight indicator at the surface.

Both, critical Sinusoidal and helical bucking limits are calculated for every meter along the drill string. Buckling is described in negative sign. However, there is no buckling of the drill string in the presented case.

It's important to note that values of weights lie in the positive area of the graph shows tension loads, while in the negative area shows a compression, which is recommended not to be in the drill pipes to avoid buckling.

As we can see, the drill string falls into the safe window. The safe window being the maximum allowable tension the can be exerted upon the drill string.
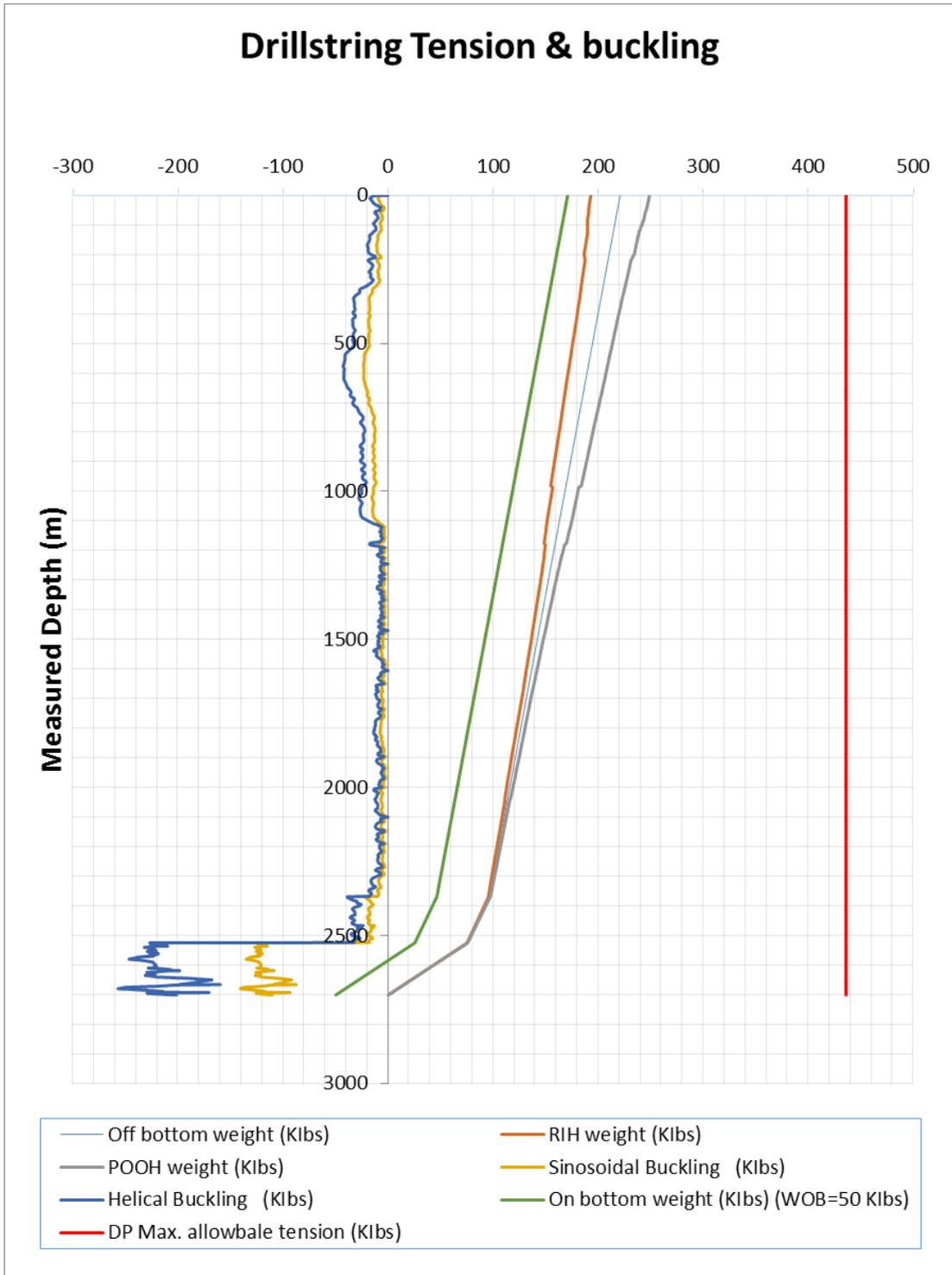
Figure 6.1 Tension loads along the drill string

6.2 The Frictional Torque Along the Drill String

Likewise, the tensional loads and frictional torque are calculated for every meter along the drill string. The calculations for four scenarios are presented:

• The torque along the drill string while the bit is off bottom in other words, free rotating weight with no axial movement.

• The torque along the drill string while the bit is on bottom. In this case 8 ft-KIbs torque on bit is added to the bottom of the string. The bit torque affects overall torque along the drill string, and therefore, higher torque is observed.

• The torque along the drill string while running in the hole, assuming no reaming, in case of back reaming, more torque will be generated and exceeds the free rotating torque.

• The torque along the drill string while pulling out of the hole, theoretically, the frictional torque is higher in both cases of with or without back-reaming. Because the frictional torque depends on the normal force, in this case, normal force during upward movement of the drill string.
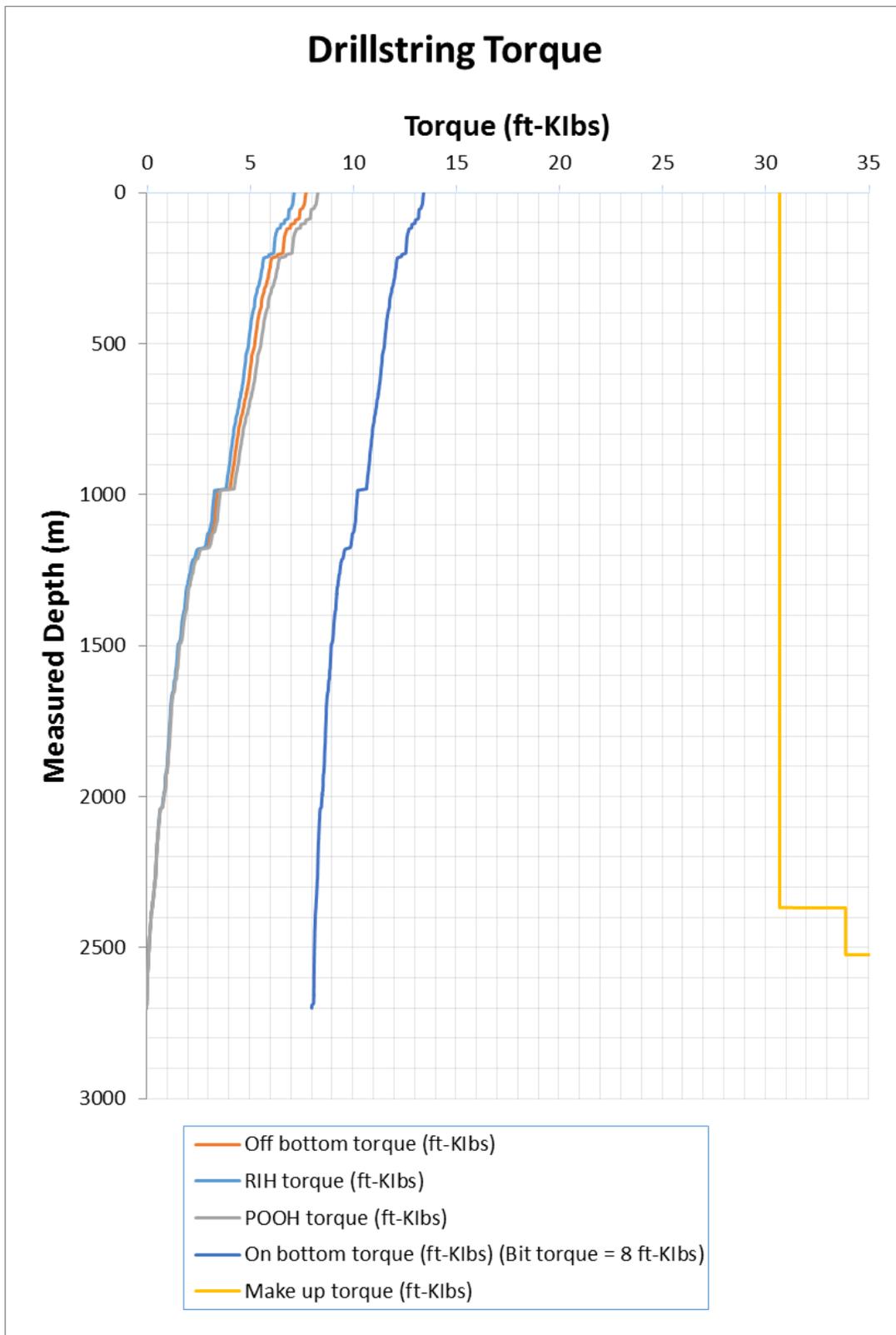
Figure 6.2 Frictional torque along the drill string

6.3 The Hook-load While Tripping

The hook-load values are calculated from the torque and drag model. These values are the summation of all tensional loads along the drill string for every meter of bit depth. Therefore, it simulates the hook-load reading at the surface for various depths unlike the previous analysis where the calculations have been done for only one bit depth of 2700m. The traveling block is ignored in the hook-load calculations. The traveling block weight is added when comparing the simulated results with actual hook-load data.

Three scenarios are implemented free rotating weight, hook-load values while running in the hole and while pulling out of the hole.
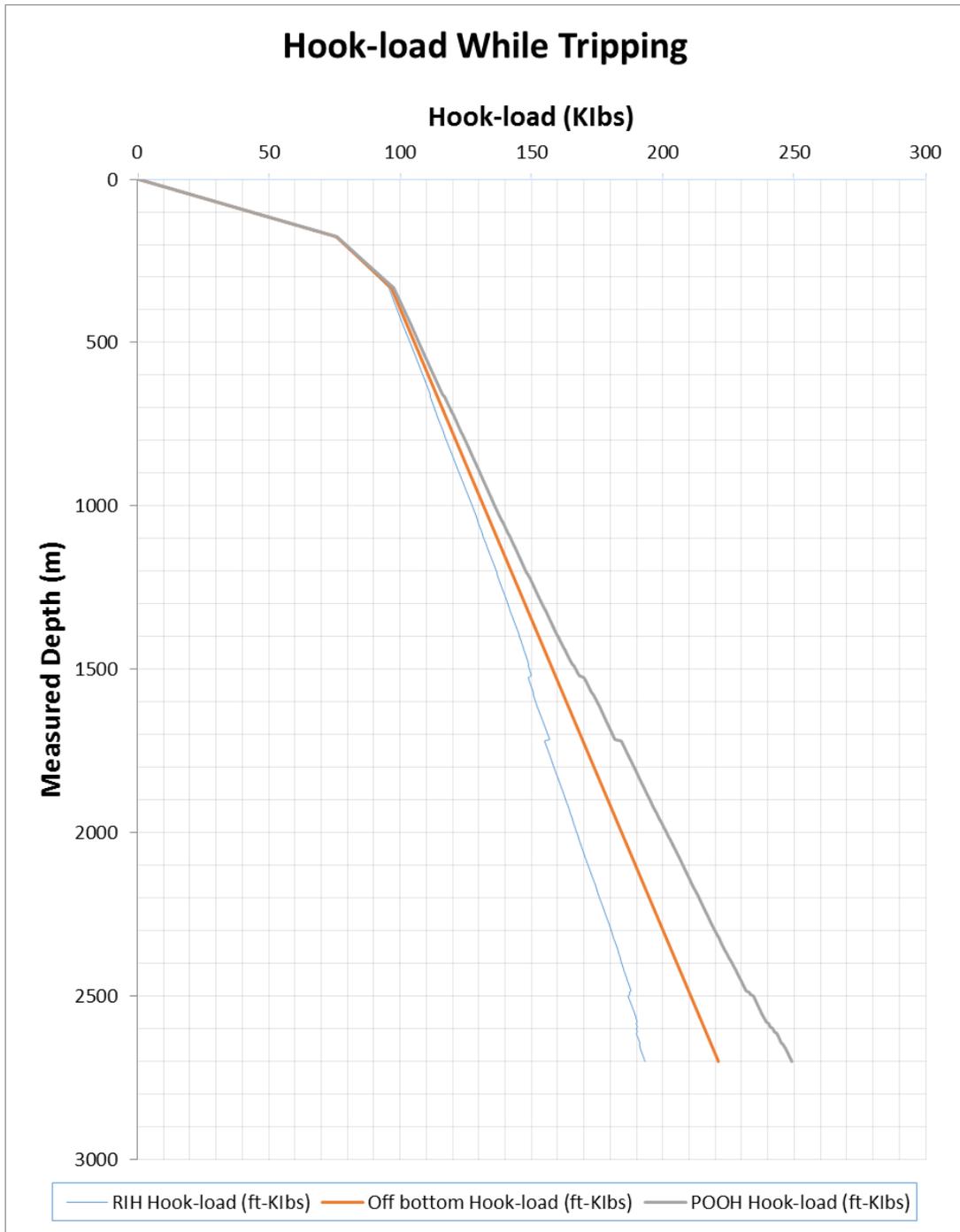
Figure 6.3 Hook-loads while tripping

6.4   The Frictional Torque While Tripping

Likewise, the hook-load while tripping and the surface torque values are calculated. These values are the summation of all frictional loads along the drill string for every meter of bit depth unlike the previous analysis where the calculations have been done for one case of bit depth of 2700m. Three scenarios were implemented, free rotating torque, torque values while running in the hole and while pulling out of the hole.
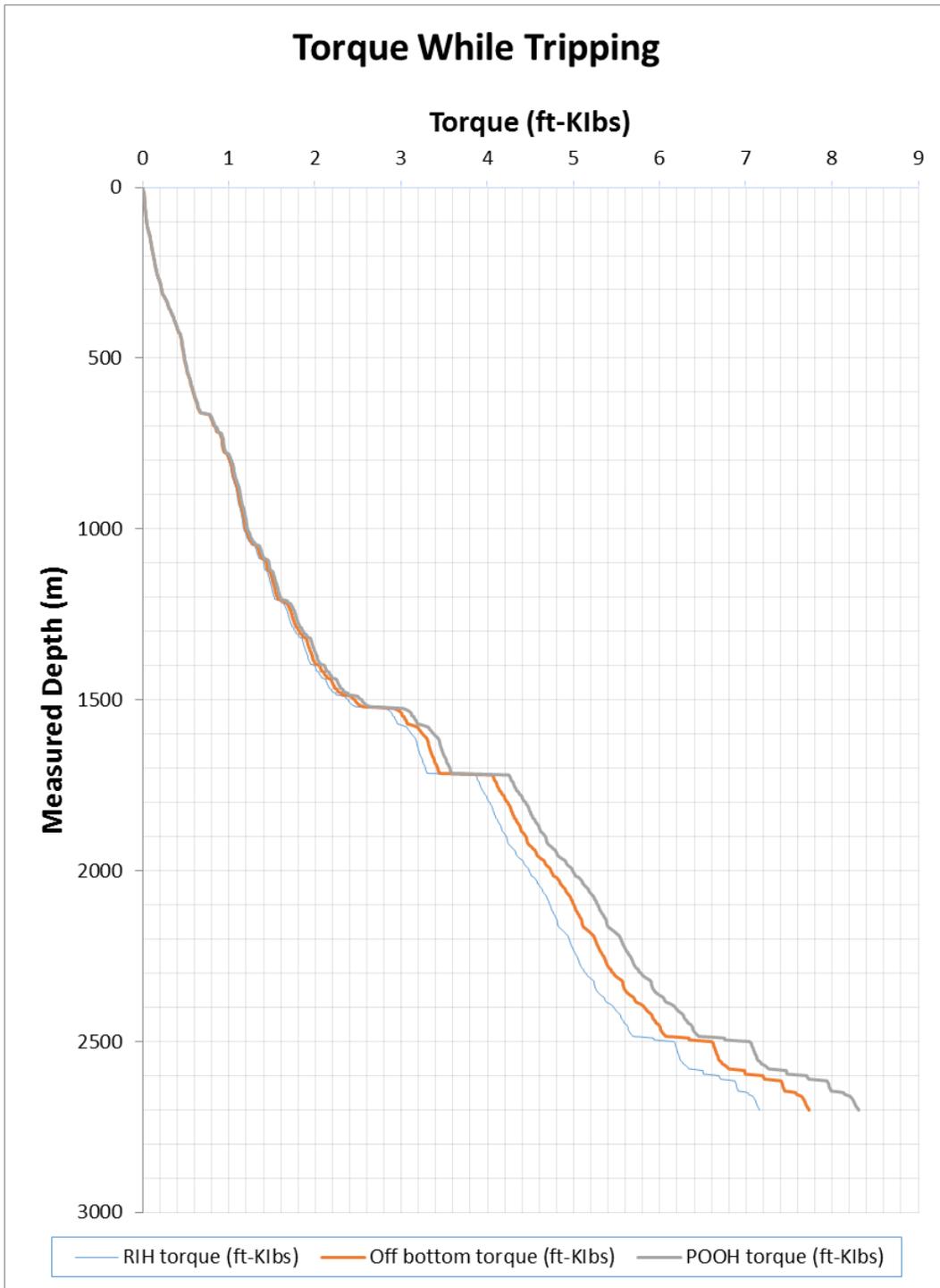
Figure 6.4 Frictional torque while tripping

6.5 Hook-load Comparison

The hook-load values in static condition are calculated from the torque and drag model. Those values are added to the traveling block weight and the weight on bit is subtracted to give the final value of the hook-load, which is compared to the actual hook-load values.

The calculated data shows good results, and the majority of errors are below 15%.

Hook-load = Static hook-load + Traveling block weight - Weight on bit
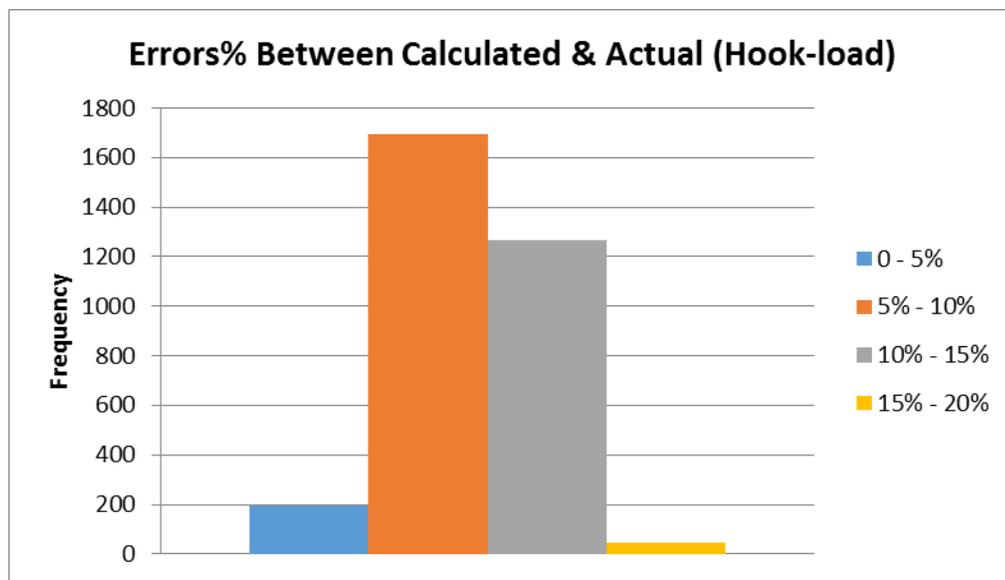
Figure 6.5 Errors between the calculated and the actual Hook-load
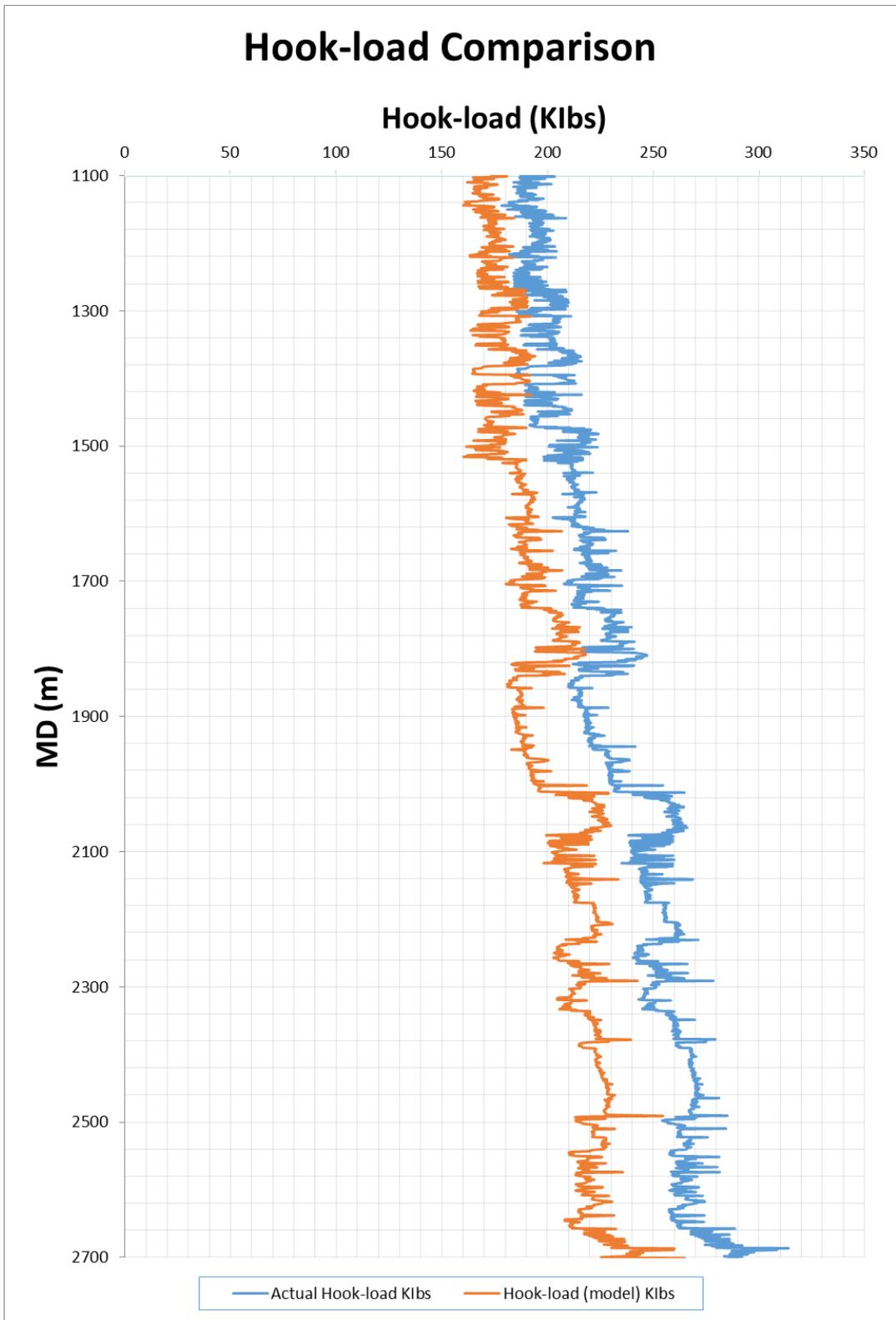
Figure 6.6 Hook-load comparison

6.6 Cumulative Torque Comparison

The torque on bit values from PayZone is added to the frictional torque from the Torque and Drag model. The result of the two torque values is the cumulative torque that is observed at the surface. The resultant torque is then compared to the actual cumulative torque for the same section.

The comparison shows that the torque which is calculated from the model and PayZone gives underestimated results. However, the torque values follow the trend of the estimated unconfined rock strength as it is shown in figure 6.8

The model did not take into consideration the exact contact area and ignored the effect of borehole diameter variations.

Looking at figure 6.9, the hole diameter is much bigger than the bit size in the upper part of the section, this indicates a borehole instability i.e. shale swelling. Cavings from failing formation of the upper part of the section makes hole cleaning more difficult, thus, increase in torque and drag. Furthermore, a narrowing hole is also observed which also increase torque and drag.
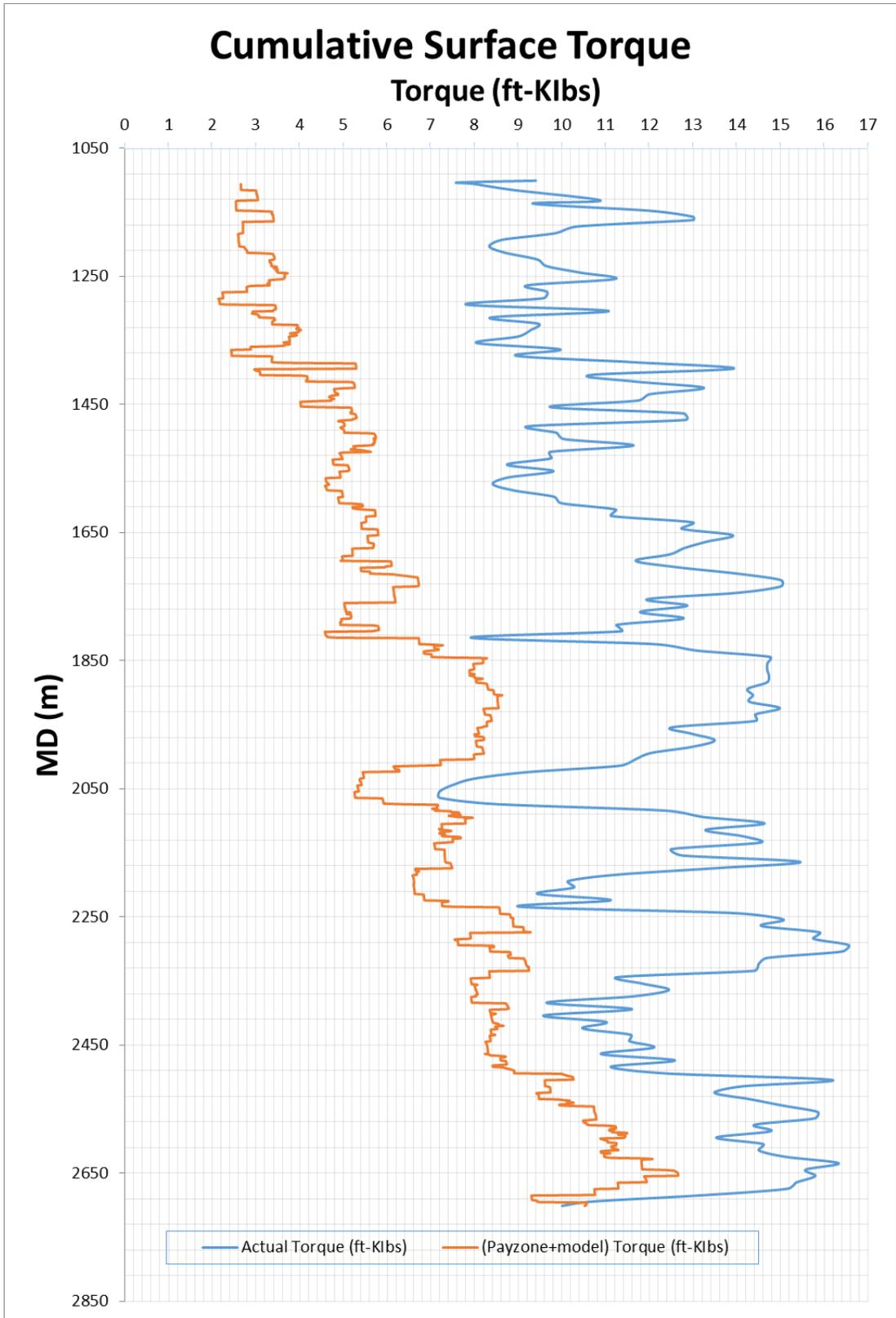
Figure 6.7 Actual torque and calculated torque
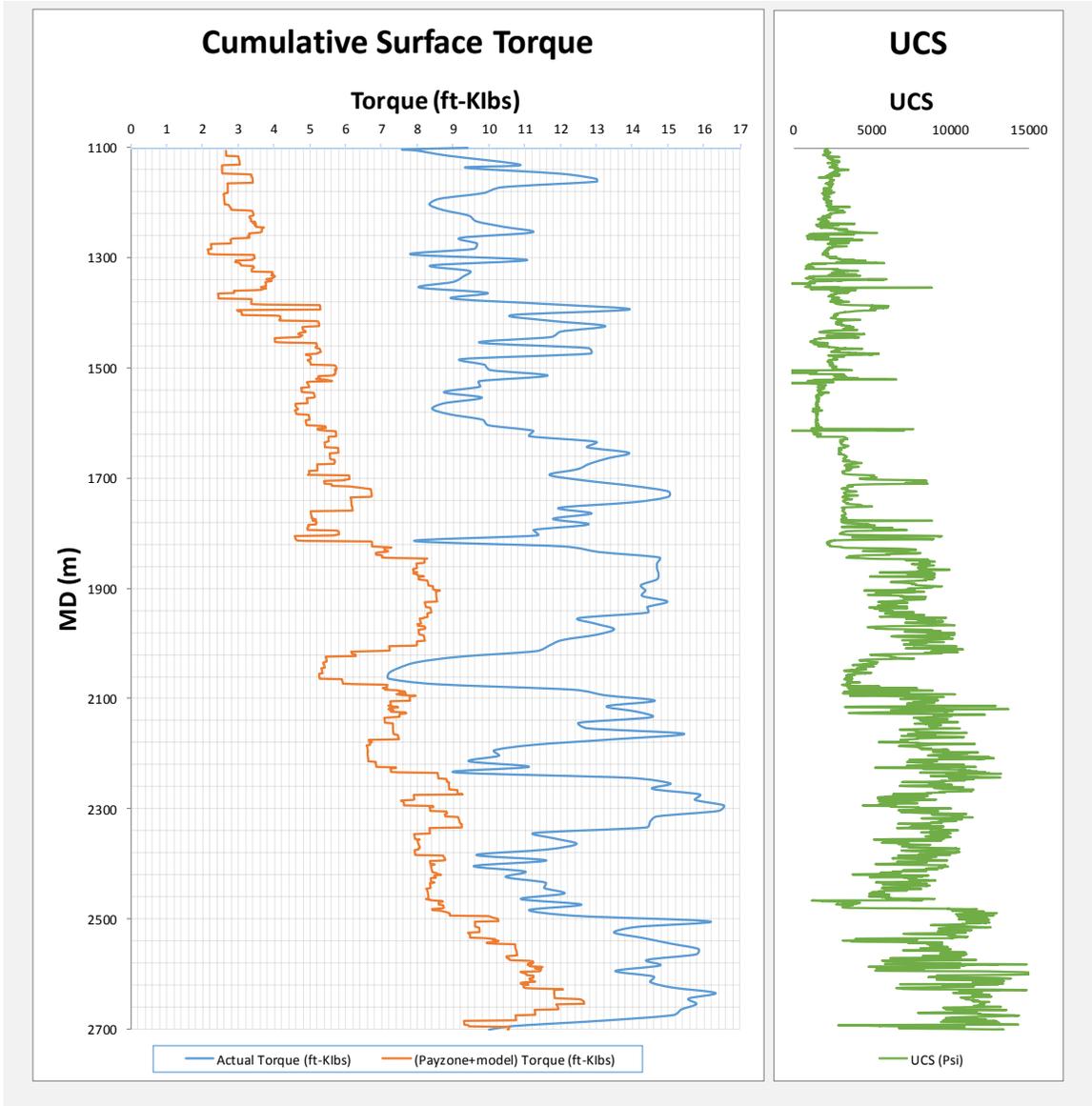
Figure 6.8 Torque and UCS
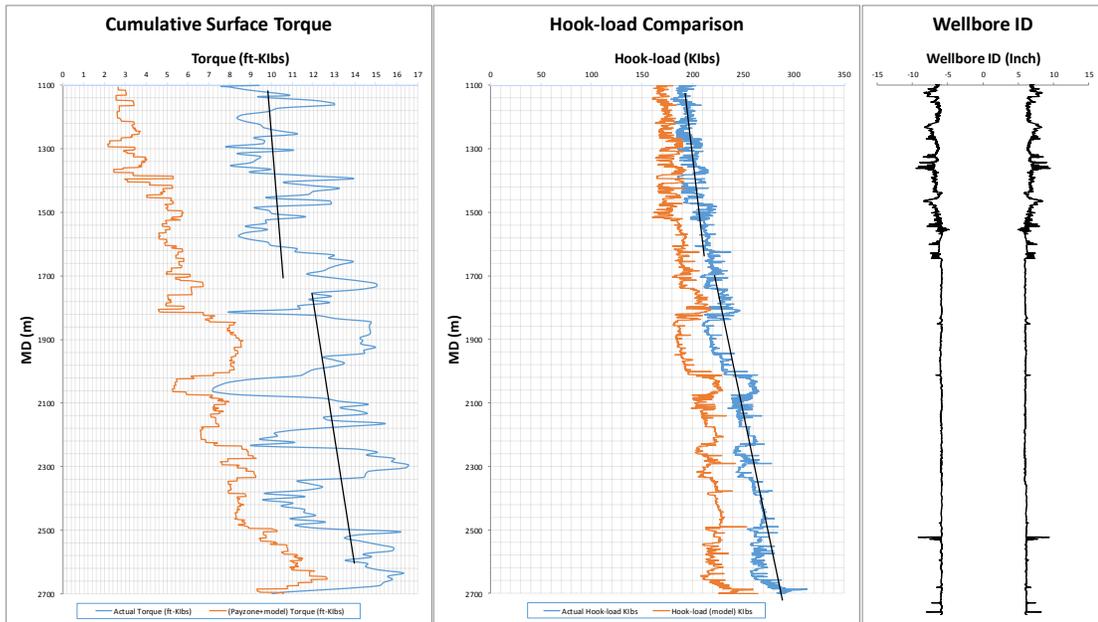
Figure 6.9 The effect of wellbore diameter on the results

7 CONCLUSIONS AND RECOMMENDATIONS

❖ The frictional torque values seem to be underestimated using the frictional model due to some uncertainties and assumptions:

- The model assumed perfectly cleaned wellbore. Therefore, no cuttings accumulation is considered.

- The model ignored the radial clearance between the string and the borehole.

- The model is a steady state model, which means that the calculations have been only made for string movement in a steady manner, and sudden transient effects such as string vibrations were not incorporated into the calculations.

- The model did not take into consideration the mud cake effect.

- The model did not take into consideration the exact contact area and ignored the effect of borehole diameter variations and borehole instability such as shale swelling and borehole closure.

- As mentioned above, from figure 6.9, a shallow swelling is observed in the upper part of the section. The cavings from failing formation of the upper part of the section makes hole cleaning more difficult, thus, increase in torque and drag. Furthermore, a narrowing hole is also observed which also increase torque and drag.

❖ The weight of the drill string acting on the wellbore is a major contributor to side forces and to the magnitude of the normal force against the wellbore. As such, heavier drill strings induce greater side forces against wellbores. Therefore, it is important to minimize the weight of the drill string within safe limits.

❖ The soft-string model used in the thesis has shown good results for the simulated vertical section. However, to simulate a more complex well profile; equations of the new 3D frictional model must be used for more accurate results.

The two models have many similarities. In a straight section there is no difference, the equations used are identical, in any curved section the models only differ in the way side force is calculated. A whole well can then be analyzed by two sets of equations, one for straight sections and one for curved sections. The model also has capability of combined axial and tangential motion, such as for reaming and drilling.

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